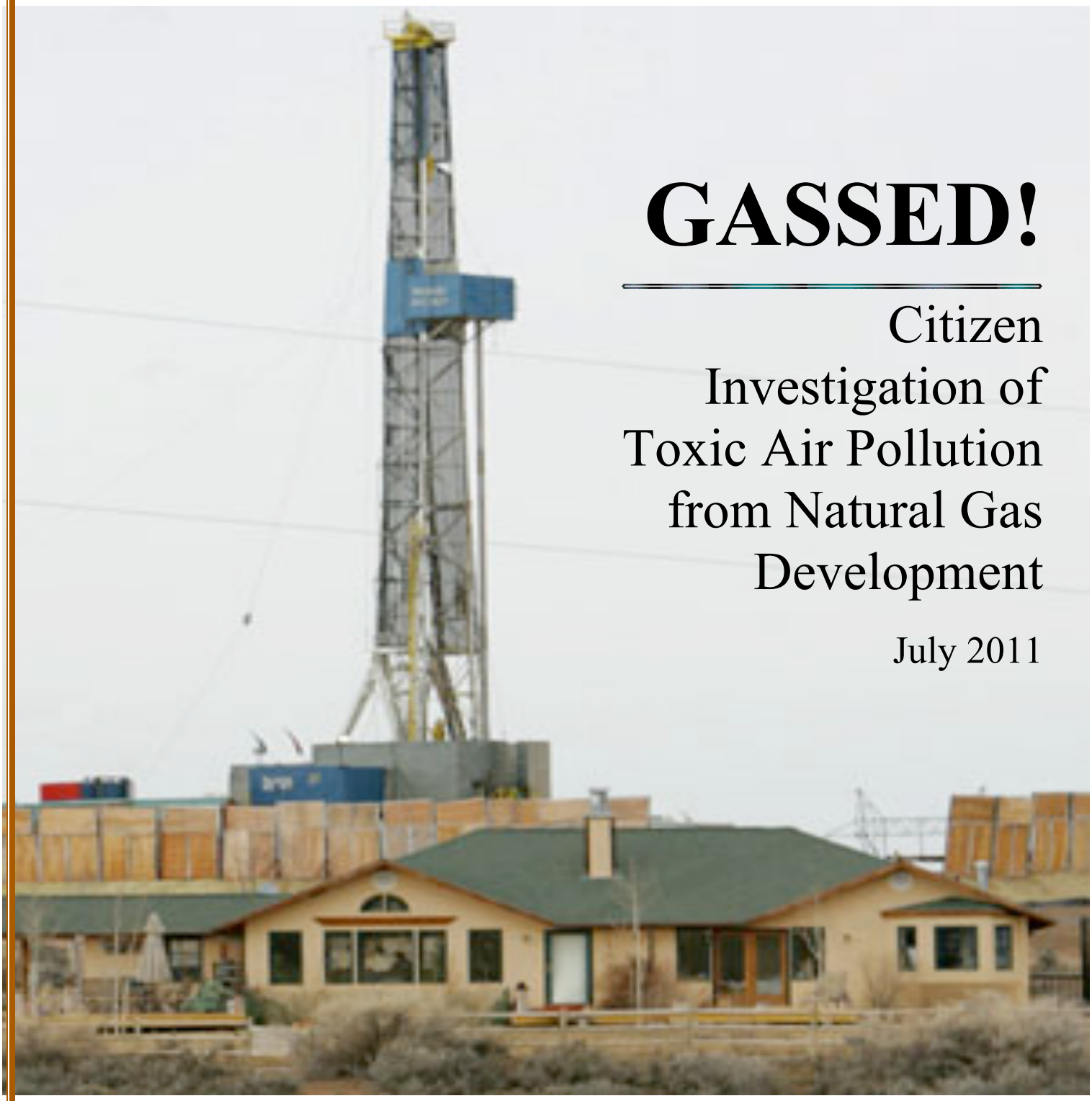


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Citizen Investigation of Toxic Air Pollution from Natural Gas Development

July 2011

10th ANNIVERSARY

Global Community Monitor

Breathing New Life into Communities

gcmonitor.org

Background on Global Community Monitor

Global Community Monitor, founded in 2001, trains and supports communities internationally in the use of environmental monitoring tools to understand and address industrial toxic pollution threats to their health and the environment.

GCM, best known as the innovator of the “Bucket Brigade”, incubates community-based groups to develop the skills, expertise, and experience to win demands around environmental health and justice. Since GCM’s approach is extremely replicable and effective, we have been invited to work with more than 40 communities in 27 countries. GCM collaborates with an established network of environmental health experts in the US and internationally to leverage resources for the communities.

Addition Information including News and Media available at:
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Executive Summary

Over the past decade, oil and natural gas exploration and production have grown at an unprecedented rate in the United States. Since necessary environmental and health regulations are not in place for this industry, residents living near oil and natural gas sites may be exposed to highly toxic chemicals on a regular basis, with their health at risk.

During 2010-11, Global Community Monitor (GCM), responding to citizen odor and health complaints, launched a community-based pilot environmental monitoring program in northwest New Mexico, southwest Colorado and western Colorado to document and measure air pollution from natural gas facilities. Through the course of this pilot study, residents, armed with their own air monitors, documented a potent mix of chemicals in nine air samples from different locations. The sites in this program are all natural gas production and processing sites, although production of oil presents similar risks. Air sampling for this project targeted many aspects of natural gas development.

Through the course of this study, several serious issues emerged:

Citizen samples exposed alarming levels of toxins in the air.

A total of *22 toxic chemicals* were detected in the nine air samples, including *four known carcinogens,* toxins known to damage the nervous system, and respiratory irritants. The levels detected were in many cases significantly higher than what is considered safe by state and federal agencies. The levels of chemicals, including benzene and acrylonitrile, ranged from three to 3,000 times higher than levels established to estimate increased risk of serious health effects and cancer based on long-term exposure.

These air samples confirm the observations, experiences and first-hand complaints of residents. Odors and health effects that have been reported for years were consistent with exposure to the chemicals found in the samples. These results underscore the need of regulatory agencies to take such complaints seriously, given the close proximity between the industry and its residential neighbors.

At least two cancer-causing chemicals, acrylonitrile and methylene chloride, were detected at high levels near natural gas operations. Neither chemical is associated with natural gas or oil deposits, but both seem to be associated with the use of hydraulic fracturing (fracking) products. Resins acrylonitrile, 1, 3 butadiene and styrene (ABS) are suspected to be present in fracking additives.

Air emissions from natural gas production are largely unregulated and unmonitored, despite being a significant source of air pollution. State and Federal air monitoring devices are located several miles from production sites, and test for criteria air pollutants rather than specific volatile organic compounds associated with natural gas exploration and production.

Oil and gas exploration and production operations are exempt from two key provisions of the Clean Air Act's National Emissions Standards for Hazardous Air Pollutants, designed to protect

public health. Because of these exemptions, the industry avoids complying with standards that are applied to other industries.

Based on the data gathered in this pilot study, highly toxic chemicals are permeating the air near homes, farms, schools, playgrounds, and town centers. Due to the lack of regulation and standards, key information about chemicals being used in the production process, including hydraulic fracturing is widely unavailable. Combined with the lack of appropriate air monitoring near production sites, **citizen right-to-know is virtually non-existent.**

Without registration of the chemicals by industry, neighbors of gas wells have no way of knowing what chemicals are stored on site, used during the industrial processes, vented to the air, water or land, or disposed nearby.

Recommendations

1. Given the proximity of residential and public property, any new sites –whether drilling, fracking, refining, or disposal – should be located at least one-quarter mile from homes, farms, schools, playgrounds, and businesses. This space would provide a **buffer zone** for industry to continue its operations while reducing community exposure to chemical contaminants.

2. The U.S. Environmental Protection Agency (EPA) should update air quality standards for oil and gas development, including the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants, based on the principles of comprehensiveness, effectiveness, full health protection, forward looking, and enforceability.

3. Until strong new rules are in place, the oil and natural gas industry can and should **voluntarily invest in equipment that reduces pollution escaping to the air**. Such equipment is readily available and financially profitable for companies. These investments would increase efficiency and production and reduce cancer-causing chemicals from being emitted into the air in communities near production facilities – saving lives and protecting the health of neighboring families.

4. Current natural gas production and processing sites should **have air monitors near all operations and equipment. All data should be made available to the public**.

5. **EPA and state agencies must enforce the current laws** on the books vigorously and impose the maximum penalties available to create a culture that prioritizes public health. Regulators should be accessible and fully funded to ensure their ability to protect public health and the environment.

As the natural gas industry continues to grow, so will the number of families neighboring and affected by the emissions. Industry and government leaders have a unique opportunity to address public health and environmental issues by implementing all of these recommendations. For

coexistence between communities and industry to be possible, chemical exposure has to be immediately addressed.

Oil and Natural Gas Development and Air Pollution

There are a variety of chemicals used and released during the drilling, fracking, and production phases of oil and gas development. In addition, different types of wastes are produced throughout the development process. Air pollution is generated at all stages of oil and gas development including wellpad construction and drilling, workovers, fracking and completion, gas compression, evaporation of chemicals from produced water and frack flowback, dehydration, separation, waste treatment and disposal, transmission and processing.

The following is a brief glossary of the life cycle of natural gas development:

Construction activity

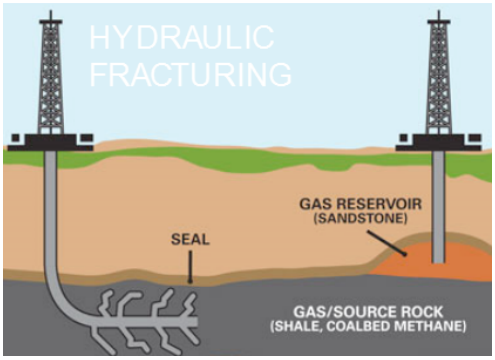
Even prior to producing natural gas, air pollution is generated by heavy construction activity including trucks and other equipment that emit air pollutants at well pads, pipelines, roads and compressor stations.

Drilling

During the drilling of a well, air pollution is generated by diesel engines powering the drill rig, as well as by any natural gas emissions being vented from the hole in the ground. These emissions could include various toxic gases, including volatile organic compounds.

Hydraulic fracturing (fracking) and completion[1]

Image from Stark Political Report



While oil and gas have always been extractable from the natural fissures in certain rock formations, some of these deposits are too diffuse to be economically feasible to exploit using traditional drilling methods. Increasing demand, however, has spurred the evolving development of fracturing technology. Pioneered in west Texas, fracking is being used to increase the productivity of drill sites in shale, coalbed methane, and tight sands formations that previously were too expensive to drill.

Fracking is dependent on fracturing fluid, typically comprised of water-based concoctions riddled with assortments of chemicals and proppants like sand. The chemical makeup of the fluid varies from company to company and site to site. The process of fracking involves perforating oil and gas wells and then pumping chemical fluid into the earth. By pumping fracturing fluid deep into the rock formation fissures under the earth at very high pressure, the cracks are expanded and then propped open with the proppant. These expanded cracks allow a single well to tap into multiple diffuse deposits.

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[1] "Hydraulic Fracturing Research Study," US EPA. Office of Research and Development. 24 May 2011. http://www.epa.gov/safewater/uic/pdfs/hfresearchstudyfs.pdf

Though fracking enables cost effective production of natural gas for the gas companies, it also comes with risks to public health and the environment. One of the least documented risks has been from air pollution caused by fracking compounds during their use, storage, or waste disposal.

Pits
Waste from drilling, fracking, or production may be dumped into open air pits to allow some of the toxic material to evaporate into the air. This can result in significant air pollution.

Land application (including land farming)
Waste from drilling, fracking, or production may be spread on the ground or otherwise applied to the land. This can result in significant air pollution.

Compressor station
Gas from wells is collected at central locations and compressed into smaller volumes at stations. Another type of compressor is located on the well site. Both types of compressors can leak and release a variety of toxic gases.

Condensate tanks
Some well sites produce semi-liquid gases along with natural gas that are stored in tanks, which can leak various toxic gases into the air.

Dehydrators
These systems are needed to remove water from natural gas and can release toxic gases in the process.

Flaring
Unwanted gases in the production process may be burned off in the open air through flares, which can produce other toxic gases as a result.

Fugitive emissions
Leaks in equipment such as pumps, valves, compressors, pipes and tanks can result in significant air pollution releases because of the number of components in gas processing.

Venting
During various stages of gas exploration, production and maintenance, gases are vented directly into the air rather than contained or flared. Venting can release large volumes of toxic gases.

Gas processing plant
The last stage of gas production involves the refining of the raw gas into the final product. This occurs at large gas processing plants, which have many sources of air emissions.

Additional waste disposal sites[2]

Wastes from various stages of gas production and processing may be sent to treatment sources including landfills, injection sites and wastewater treatment sites, which can also release air pollution.

[2] "Public Health and Toxics." EARTHWORKS. 20 March 2011, http://www.earthworksaction.org/Health%20and%20Toxics.cfm

Air Pollution and Human Health Impacts of Natural Gas Development

Air pollution can affect our health in many ways, with both *short-term* and *long-term* effects. Different groups of individuals are affected by air pollution in different ways. Some individuals are much more sensitive to pollutants than others. Sensitive populations, including young children and elderly people, often suffer more from the effects of air pollution. People with health problems such as asthma, heart and lung disease may also suffer more when the air is polluted. The extent to which an individual is harmed by air pollution usually depends on the **total exposure** to the damaging chemicals, i.e., the *duration of exposure* and the *concentration of the chemicals.* Total exposure must be taken into account when assessing air pollution risks.

Examples of **short-term effects** include irritation to the eyes, nose, and throat, and upper respiratory infections such as bronchitis and pneumonia. Other symptoms can include headaches, nausea, and allergic reactions. Short-term air pollution can aggravate the medical conditions of individuals with asthma and emphysema.

Long-term health effects can include chronic respiratory disease, lung cancer, heart disease, and even damage to the brain, nerves, liver, or kidneys. Continual exposure to air pollution affects the lungs of growing children and may aggravate or complicate medical conditions in the elderly.[3]

Chemicals such as benzene, toluene, ethylbenzene and xylene (BTEX) are known to be present around natural gas development sites, both from the gas deposits as well as chemical additives. Our independent testing found significantly high amounts of these toxic gases downwind of various sites. Health effects from BTEX include dizziness and confusion, eye, nose and throat irritation, birth defects, kidney, liver, and neurological damage, and cancer. For example, benzene is known to cause leukemia.[4]

Hydrogen sulfide was also found in the Bucket tests, warning signs for the gas are often visible near well pads. Long-term exposure to hydrogen sulfide is associated with an elevated incidence of respiratory infections, irritation of the eye, nose and throat, coughing, breathlessness, nausea, headache, and mental health impacts, including depression.[5] It is recommended, that workers handling hydrogen sulfide be equipped with hydrogen sulfide monitors, respirators, and rescue packs for protection in the event of elevated exposure; the public has no such protection.[6]

Additional toxic substances were detected at high levels in the air samples, including toxic gases not previously associated with natural gas development, suggesting that substances possibly associated with fracking additives may have been released into the air.

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[3] "How Can Air Pollution Hurt My Health." Health Effects of Air Pollution, Lawrence Berkeley National Laboratory, March 2011, http://www.lbl.gov/Education/ELSI/Frames/pollution-health-effects-f.html
[4] NRDC, Drilling Down, October, 2007, table on page vi
[5] Chernaik, Mark. Data Interpretation Synthesis Letter. Science for Citizens. 16 Feb. 2011
[6] Air Products, Material Data Sheet, http://avogadro.chem.iastate.edu/MSDS/hydrogen_sulfide.pdf

Overall, air samples gathered for this project showed that neighbors of the natural gas operations in the target communities are breathing multiple chemicals that can cause an increased risk of cancer and other serious health effects. There are no health-based standards for exposure to multiple chemicals, although the negative health impacts are considered to be increased.

Natural Gas Development in Colorado and New Mexico

Growth in Project Areas

GCM worked with two communities in the San Juan Basin—one in southwest Colorado and a second in northwest New Mexico. In addition, GCM worked with a third community in Garfield County in western Colorado.

- ***Colorado's natural gas production has risen 450% since 1990 with over 27,000 active wells statewide.*** [7]



- ***Currently there are approximately 3,400 wells in La Plata County, CO.*** [8]

Image from BP.com

- ***There are approximately 21,000 wells in San Juan County, NM***
-
-
  - ***The approximate total of wells in the entire San Juan Basin is 35,000 wells*** [9]

Image from Realtor.com

- ***In western Colorado, Garfield County has an estimated 8,249 active wells with 2,037 new permits approved in 2010*** [10]



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[7] "Background." Western Colorado Congress, 20 March 2011, http://www.wccongress.org/gvca.htm#background
[8] "Natural Resources- Oil and Gas." La Plata County Planning Department, 25 March 2011, http://www.co.laplata.co.us/departments_and_elected_officials/planning/natural_resources_oil_gas
[9] United States Department of Interior, Bureau of Land Management, **Farmington Resource Management Plan** (December 2003) Final **RMP**/Record of Decision
[10] May 2011 Colorado Oil & Gas Conservation Commission Staff Report

Target Communities

GCM worked with communities in northwest New Mexico and southwest Colorado in partnership with the San Juan Citizens Alliance. The project also included communities in western Colorado in partnership with the Western Colorado Congress. The communities were trained in air monitoring and bucket sampling around natural gas development sites.

Northwest New Mexico: Aztec and Farmington Area

Of the three communities involved in this pilot project, northwest New Mexico has the longest history of complaints about natural gas drilling. Natural gas has been drilled for, and produced, in northwest New Mexico for over 60 years with natural gas facilities interspersed among residential areas. Community residents in northwest New Mexico have noticed strong odors since the late 1980s, reported as smelling like rotten eggs, petroleum and sewage, around the ever-expanding oil and gas industry. Residents have experienced nose, throat and eye irritation that occasionally would last for hours after smelling the odors. When the odors increased in frequency, so did the associated acute health effects.

Energy companies in the area, including BP, Energen, XTO, Devon, Conoco Phillips, Enterprise, Williams and Questar, are associated with drilling for and transporting natural gas, where operations at sites can include fracking by numerous companies. San Juan County in Northwest New Mexico consists of more than 100,000 residents potentially affected by natural gas production, either by living near a gas well or near the plants that process the natural gas.

There are many gas wells near schools, churches, private residences and community centers. Natural gas odor incidents are frequent, along with adverse health effects in the community. For example, in December 2009, one of the members of the San Juan Citizens Alliance and long-term area resident Shirley McNall went out to get her mail. She was immediately struck with an extremely potent rotten egg odor and overcome with dizziness and nausea. According to McNall, she fell to the ground and was forced to crawl back into the house. While the symptoms began to slowly subside, she reported numbness in her lips that lasted for three days after the incident.

During less severe odor incidents, residents commonly reported headaches, nausea and dizziness in addition to nose, throat and eye irritation.



Shirley McNall- Aztec, NM

The health effects and reported odors could be associated with chemical exposure. McNall and other residents have documented odors most frequently during the late evening through the early morning hours. This could be related to the industrial process and/or weather patterns that concentrate or bring the toxic fumes near homes.

Community members call the New Mexico Oil and Gas Conservation Division frequently, often multiple times a week, to report these odors. However, no satisfactory permanent solutions have been reached. On occasion, a representative of the New Mexico Oil and Gas Conservation Division will conduct an on-site investigation. During one of these investigations, the representative informed the residents that the most likely cause of the odors is "treated" hydrogen sulfide. This is a major concern because hydrogen sulfide is highly toxic and, while its presence requires formal signage by law, no signage was present at the well under investigation.

Homeowners are not generally informed of the toxic risk when their property is in proximity to natural gas facilities. Split estate situations where mineral ownership is separate from private surface ownership creates confusion and uncertainty surrounding where wells can be drilled in relation to homes. Numerous contractors and subcontractors may be involved with natural gas facilities, further complicating responsibilities and actions. The New Mexico Environmental Department and the U.S. Environmental Protection Agency's (EPA) efforts to monitor and evaluate air impacts from natural gas resources in northwest New Mexico have been limited.

Southwest Colorado: Durango

This troubling trend is not unique to the northwest corner of New Mexico. The expanding oil and gas industry has spread into communities in Colorado.

La Plata County, located in southwest Colorado where the southern Rockies meet the high desert country of northern New Mexico, is home to three municipalities, four river drainages, and a sovereign Indian nation. It is known for its outdoor activities including hiking, rock climbing, backpacking and white water rafting along the Animas River, and for the incredibly lucrative coalbed methane field that underlies it.

Coalbed methane development has been going on here since in the mid-1980s. The environmental degradation associated with development has been documented to include coal seam fires and hydrogen sulfide and methane seeps at the Fruitland formation outcrop. The full impacts of development on air quality and public health, however, remain largely unexamined.

Due to split estate status, energy companies can lease the mineral rights underneath the property of a homeowner. Insufficient setbacks and surface owner protections allow the oil and gas industry to place facilities directly next to homes and schools. Near Sunnyside Elementary School, air monitoring on January 7, 2011 showed elevated levels of four known carcinogens. Two of the carcinogens were recorded at levels that are considered to be an unacceptable long-term exposure risk.



Josh Joswick- Durango, CO

LaPlata County has an estimated 3,400 wells. Many county residents therefore live in or adjacent to the 'gas patch,' often times in close proximity to gas wells, compressor stations, dehydrators, and processing plants. This incompatible mix of industrial activity in rural residential areas has had an impact on

people's lives. Gas patch residents in La Plata County report odors similar to their neighbors in New Mexico. These odors, smelling like burning oil, car exhaust, and burning rubber, are most frequently noticed around well sites.

Aaron Mallet, a La Plata County resident active with the Bucket Brigade, stated on September 28, 2010: "On a regular basis there is an acrid smell in the air that emanates from that well pad."[11] Residents have also documented headaches, sore throats and burning nasal passages during these odor incidents.

Western Colorado: Battlement and Silt Mesas

Lastly, GCM worked with the communities of Battlement and Silt Mesas in Garfield County, Colorado. Battlement and Silt Mesas are two rural communities experiencing impacts from nearby development of natural gas.

Battlement Mesa is an unincorporated retirement community of 5,500 residents in western Garfield County. Originally constructed by Exxon in the 1970s for workers in the oil shale industry,[12] it was later marketed as a destination for retirees seeking a peaceful place to spend their golden years. Exxon eventually sold the surface properties but retained the mineral rights to extract the fossil fuels beneath Battlement Mesa at any time in the future.

Community members watched as natural gas wells incrementally came closer to Battlement Mesa, and the residents began to wonder if drilling would be allowed within their retirement neighborhood.

Dave Devanney- Battlement Mesa, CO



In 2009, Battlement Mesa learned of a proposal to drill 200 natural gas wells within its borders, including sites near homes, along the Colorado River, on the golf course, and near a school. Battlement Mesa residents called for thorough scientific research of the potential public health impacts of natural gas development before any permitting decision. After hundreds of residents signed a petition, a groundbreaking Health Impact Assessment was commissioned for drilling within Battlement Mesa and county officials delayed any new drilling inside of the retirement community until this process was completed. Drilling, however, began just outside the border of the community and community members began complaining of noxious fumes being emitted.

Battlement Mesa residents documented strong petroleum-like odors in the middle of the night and early mornings. Residents believed that these strong petroleum, diesel and chemical smells were caused by nearby fracking operations. Nearby residents began experiencing health effects such as throat and nose irritation, headaches, itching skin, burning eyes, and dizziness. Residents

[11] Mallet, Aaron. Pollution Log 28 Sept. 2011
[12] Oil Shale is a different formation than the source of shale gas.

called the Colorado Oil and Gas Conservation Commission to formally report the odor events; they started documenting odor occurrences, and they contacted local authorities.

The Colorado Oil and Gas Conservation Commission cited the operator for failing to capture nuisance odors derived from its operations. The company was encouraged to use additional vapor recovery techniques during flowback operations to reduce odors (but never received a monetary penalty). Residents noticed a marked diminishment of the odors, but around the same time, in November of 2010, a local news channel highlighted nearby Silt Mesa residents' problems with natural gas development. Silt Mesa residents reported odors they thought were caused by natural gas activity, and Dave Devanney of the Battlement Concerned Citizens contacted them.

Silt Mesa is a network of irrigation canals and small ranches, sitting along the Colorado River between Rifle and Silt, Colorado. Drilling for natural gas is taking place near homes and water supplies, presenting many of the same challenges as on Battlement Mesa.

One Silt Mesa family with two young sons had three natural gas drill rigs surrounding its property, each with ongoing flaring. The nearest flare stack was less than one-half a mile from their home. Family members reported pungent odors of rotten eggs followed by severe headaches, nosebleeds and rashes. The nosebleeds were persistent and heavy, much different than the average nose bleed. The mother described it as "almost like hemorrhaging." The youngest son developed a full body rash, which prompted a doctor visit. Upon examination, the doctor immediately told the Silt Mesa family to evacuate their home.

Although the family was forced to vacate their home because of nearby industrial activity, the state did not issue any violations. According to Colorado rules, Silt Mesa is not a High Density area, therefore, drilling for natural gas in the area does not warrant additional safety precautions.[13]

Today, the Silt Mesa family has left their home and put it up for sale. An air sample taken on January 15, 2011, on their property, contained levels of hydrogen sulfide more than 185 times above the long term level set by the U.S. EPA (2 $\mu g/m^3$) to estimate increased risk of serious health effects.

This Silt Mesa family, as well as the Battlement Mesa residents, call frequently to report odor complaints and other incidents of non-compliance. They call the Colorado Oil and Gas Conservation Commission, the Garfield County Oil and Gas Department, the Colorado Department of Public Health and Environment, and occasionally, the Environmental Protection Agency. The communities have seen worse local air quality since natural gas development markedly increased in Garfield County, although limited air monitoring is conducted by local and state authorities.

Collectively, nine air samples were taken by the Bucket Brigades. The members of San Juan Citizens Alliance and Battlement Concerned Citizens have taken the results to local officials and

[13] Colorado Oil and Gas Conservation Commission. "Series Safety Regulations" 2 June 2011. http://cogcc.state.co.us/

the U.S. EPA, but, to date, the agencies have not taken any action. Most of the residents feel their concerns have fallen on deaf ears.

A press release was issued in Aztec, New Mexico and Durango, Colorado announcing the air sample results. The residents still have not received an adequate response from the regulatory agencies. On Monday, April 4, 2011, Katee McClure sent an e-mail to the New Mexico Environment Department inquiring about who is responsible for enforcing air regulations. Although, the agency did respond in a timely manner, it provided incorrect information regarding standards for hydrogen sulfide pollution while failing to take responsibility or provide information for the responsible agency.[14]

[14] McClure, Katee. 4 April 2011

Citizen Air Sampling: Bucket Brigade Projects

Community-Based Air Monitoring: A Crucial Piece of the Puzzle

Building a trail of evidence

Regulatory and environmental agency personnel are not available at all hours to come out during a pollution incident. In the case of Colorado and New Mexico, a proper citizen complaint system is not established. A proper citizen complaint system would include a telephone hotline followed by rapid response from regulatory agencies and timely air sampling during odor incidents. Community-based monitoring provides an opportunity for residents to respond immediately to the pollution incident with sampling equipment and to contact agency personnel.

GCM trained members of the Western Colorado Congress, the San Juan Citizens Alliance, and other community members to keep a record of pollution incidents. These records include: the location, nature, and duration of the incident; the wind direction, health effects or property damage; and how the incident was addressed – by a call to the regulatory agency or the company suspected or known to be the source of the pollution, or informative calls to other neighbors.

Pollution incident records are referred to as "pollution logs." Pollution logs filled out by community members ensure that a record is maintained beyond regular agency business hours. Community members are also encouraged to take pictures and/or use a video camcorder to catch a visual image of the pollution.

Bucket Brigades provide evidence and hard science to support the anecdotal stories of health impacts that all affected communities know too well: strange odors causing nausea, stinging eyes, burning noses, sore throats, coughs, and other distressing health symptoms. Community-based monitoring engages community members in record maintenance, site identification, operation of monitoring equipment, documentation, and custody and shipping of the sample.

The information gathered by Bucket Brigades, combining science with community experience and reports, helps bridge the gap between communities, regulators and industry. Air sampling and monitoring can provide key evidence exposing chemical exposure, can be a tangible way to show that the air pollution has decreased in a community, and can help build relationships where community members coexist with their industrial neighbors.

Bucket Brigade Training & Methods

To begin a project, GCM conducts a research assessment of toxic hazards in a target community and identifies the appropriate environmental monitoring tools that will assist community members in investigating their health concerns and exposures. We review the data on pollution sources and toxins and prioritize the most serious for early action. Due to the lack of publicly available data regarding the air emissions from natural gas drilling and refining sites, we had little research available for reference in this project.

All Bucket Brigade trainings are conducted on site, in the local community. For this project,

GCM was given a local tour by community members in areas near Durango, Colorado; Battlement/Silt Mesas, Colorado; and Aztec, New Mexico in late July, 2010. During the training, GCM provided a day-long classroom training, including background on pollution and environmental health, how to document pollution incidents, hands on training and how to use monitoring equipment. We worked with the local community members to co-design an environmental sampling plan.

The training and plans emphasize standard scientific methods. Community members learn how the monitoring equipment works, the best time to use it, and the appropriate paperwork to fill out before shipping a sample to the lab. The Bucket Brigade's work is strengthened by following stringent Quality Assurance/Quality Control (QA/QC) protocols and the use of EPA approved labs.

The Bucket Monitoring Equipment

Due to the nature of the uncertainty of the emissions associated with natural gas drilling, hydraulic fracturing and refining, this project chose to use the Bucket as the monitoring equipment. The Bucket is modeled after the Summa Canister,[15] but has some advantages in its use.

The Bucket is portable, requiring only a tedlar bag and vacuum to take the grab sample. Air is "grabbed" out of the air for two to three minutes and captured in the bag. Once the sample is taken, the tedlar bag is sealed, removed from the bucket and sent to the lab for analysis.



The air sampling Bucket, gcmonitor.org

[15] State of Nevada, Division of Environmental Protection. "Summa Canister Sampling". http://ndep.nv.gov/fallon/summa.pdf

The lab analysis is conducted by Columbia Analytical Services in Simi Valley, California. The lab utilizes EPA method TO-15 and ASTM D 5504-08 method for sample analysis. The TO-15 analysis includes a spectrum of more than 70 volatile organic compounds and the ASTM D 5504-08 method is used to test for 20 sulfur compounds.

Once the community members are trained on the equipment, the buckets are kept at various locations in the community – selected based on the location of odors and health symptoms that have been experienced and reported. When an odor incident occurs, Bucket Brigade members join together to bring a bucket to the site of the odor incident and take a sample of the air at the time of the odor.

Results & Discussion of Results

Individual sample results and overall trends:

For this project, communities in New Mexico and Colorado took a total of nine air samples between September 2010 and January 2011. This report documents serious toxic air pollution generated at various points of the life cycle of natural gas development. Targeted sampling sites included well pad, compressor station, gas separation plant, dehydrator and waste disposal site. Serious cancer-causing chemicals were detected at elevated levels, including chemicals associated with the fracking process used increasingly by energy companies.

While bucket samples are short-term grab samples of the air breathed by community members living near natural gas development facilities, letters and pollution logs reveal that the odors are persistent and occur on an ongoing basis. We therefore consider the data to be indicative of long-term exposures, and the expert interpretation used in this report compares the data to pollutant levels linked to long-term health effects.

A total of 22 toxic chemicals were detected in the nine air samples, including four known carcinogens, toxins known to damage the nervous system, and respiratory irritants. The levels of chemicals detected were in many cases significantly higher than is considered safe by state and federal agencies. The levels were between three to 3,000 times higher than levels established by public health agencies to estimate increased risk of serious health effects and cancer based on long-term exposure.[16]

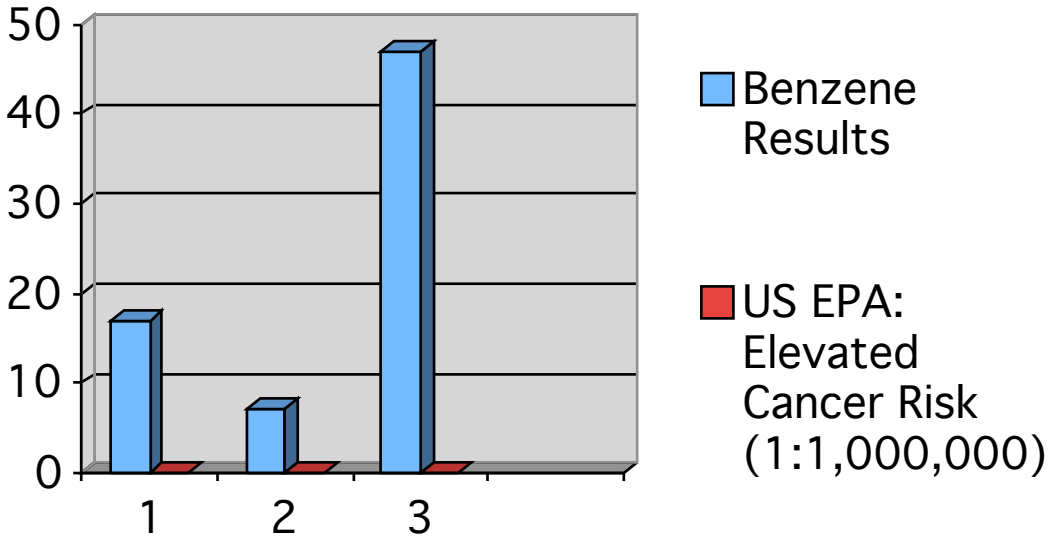
The most significant results:

- ***Benzene***, a known carcinogen, was found at high concentrations in four air samples at levels between 6.3 and 47 $\mu g/m^3$. These levels are 48.5 to 800 times higher than the level set by the US EPA of 0.13 $\mu g/m^3$ to estimate increased cancer risk from long-term exposure.[17]

  Benzene can also cause serious non-cancer health effects which can damage the blood and nervous system Levels of benzene in one of the nine samples, collected on January 7, 2011 near the Sunnyside Elementary School, Durango, Colorado, exceeded the level set by the U.S. EPA for benzene (30 $\mu g/m^3$) to estimate increased risk of non-cancer health effects.

[16] This report defines an elevated cancer risk as 1:1,000,000
[17] http://www.epa.gov/ttn/atw/toxsource/table1.pdf

Sample 1: 200 Montana St Bloomfield NM
Sample 2: Bondad 33-10 #26 Williams Well, Durango, CO
Sample 3: Intersection of US 550 & CR 218 Durango, CO, near Sunnyside Elementary



- ***Acrylonitrile***, a human carcinogen, was found in five samples at levels between 7.9 and 30 μg/m^3. These levels are 790 to 3000 times above the U.S. EPA level of 0.01 μg/m^3, set to estimate an increased risk of cancer from long term exposure. All of these levels correspond to what EPA would consider an "unacceptable cancer risk" in that long-term exposure is associated with a cancer risk of greater than 100 in a million.[18]

  Acrylonitrile is also a respiratory irritant, causing degeneration and inflammation of nasal epithelium. Levels of acrylonitrile in the five samples exceeded the level set by U.S. EPA for risk of increased non-cancer health effects from long term exposure (2 μg/m^3) by 3 to 15 times.[19]

- ***Methylene chloride***, a human carcinogen, was found in five samples at levels between 7.9 and 17 μg/m^3. These levels are 3 to 8 times higher than the level set by the U.S. EPA (2.0 μg/m^3.) to estimate an increased risk of cancer from long-term exposure.

[18] Communication from Miriam Rotkin-Ellman, Natural Resources Defense Council. 7 June 2011
[19] The USEPA Reference Concentration (RfC) is an estimate of a continuous inhalation exposure concentration to people (including sensitive subgroups) that is likely to be without risk of deleterious effects during a lifetime.

- ***Ethylbenzene***, a human carcinogen, was found in five samples at levels between 5.1 to 22 μg/m^3. These levels are 12 to 55 times higher than the level set by the US EPA (0.4μg/m^3) to estimate increased cancer risk cancer from long-term exposure.

- ***Xylene***, were found at a level of 100 and 154 μg/m^3. These levels exceed the U.S. EPA's level for estimating increased non-cancer health risks of 100 μg/m^3.

- ***Hydrogen sulfide*** was found in one sample at 370 μg/m^3 which is more than 185 times above the long term level set by the U.S. EPA (2 μg/m^3) to estimate increased risk of serious health effects.

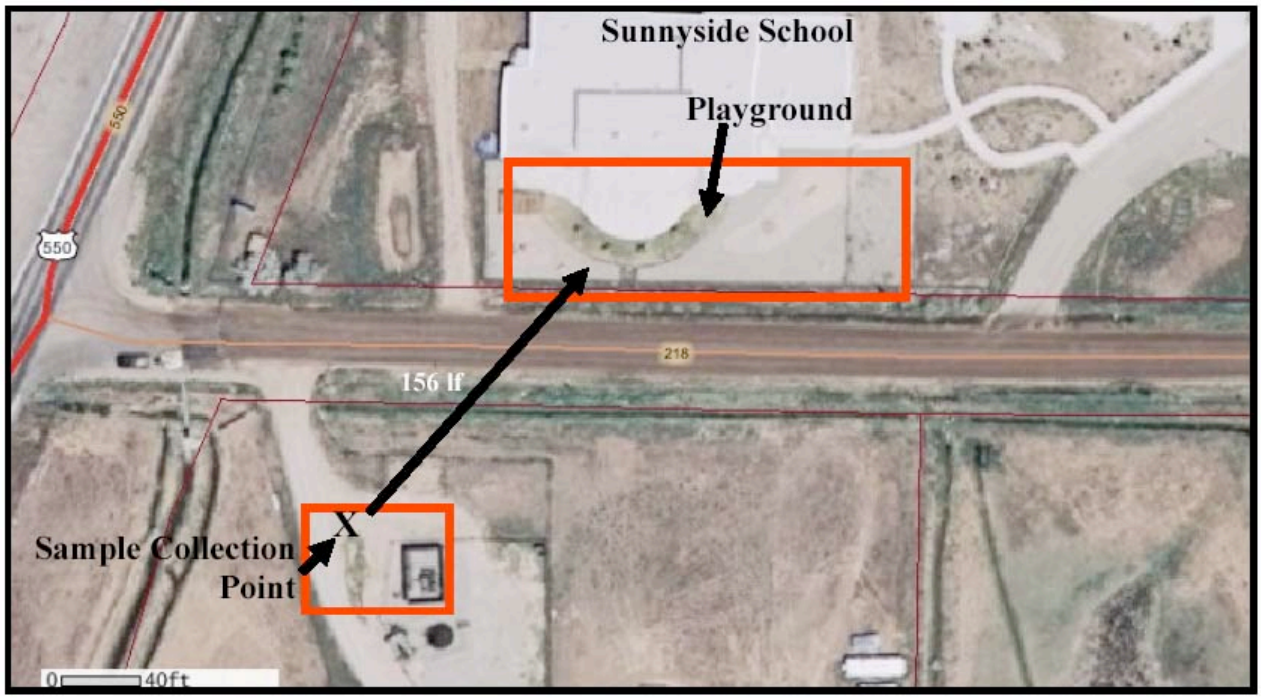
  Long-term exposure to hydrogen sulfide is associated with an elevated incidence of respiratory infections, irritation of the eye and nose, cough, breathlessness, nausea, headache, and mental symptoms, including depression. The World Health Organization's Guideline Value for exposure to hydrogen sulfide is 7 μg/m^3 over a 30-minute period.

For the first time, at least two cancer-causing chemicals found at high levels, acrylonitrile and methylene chloride,[20] were detected by the air samples at a variety of natural gas development sites. Neither is associated with natural gas and oil deposits, but both have been shown to be associated with chemicals used in the fracking process to increase yields from oil and gas deposits.

The air samples found high levels of chemicals that can cause symptoms that match the odors and health effects reported by nearby residents for years. This confirms the need for agencies to take such complaints seriously and to better monitor and require pollution controls at all points of natural gas production and processing.

[20] Cherniak, Mark. Data Interpretation Synthesis Letter. 16 Feb 2011

Image from San Juan Basin Health Department



Bucket Brigade Sample Collection Event
January 7, 2011
Dehydrator Facility Located
156 lf from Sunnyside Kindergarten Playground

Results near the Sunnyside School in La Plata County, Colorado

On January 7, 2011, two members of the Bucket Brigade team in La Plata County, Colorado, took an air sample less than 50 feet from a dehydrator that is less than 200 feet from the Sunnyside Elementary School playground near Durango. This natural gas dehydrator is a frequently suspected source of unknown chemical odors. The sampling team on site experienced odors. Subsequent analysis of the air sample revealed a number of toxic chemicals, including four known carcinogens.

A significant level of acrylonitrile, a human carcinogen, was detected in this sample (as it was in four other samples in this report) at a level above which is considered by the US EPA to be an unacceptable long-term exposure risk.[21] Methylene chloride, a human carcinogen, was also detected in this sample (as it was in four other samples) at a level above which is considered to be an unacceptable long-term exposure risk.

Two more carcinogenic substances, benzene and ethylbenzene, were also detected in this sample at levels above that which is considered to be an unacceptable long-term exposure risk. The

[21] http://www.epa.gov/ttn/atw/toxsource/table1.pdf

level of benzene in this sample, 47 ug/m^3, is notable in that it is the highest level of benzene detected so far in this area by the Bucket Brigade. Besides acting as a carcinogen, benzene can also adversely impact the human immune system by decreasing circulating levels of lymphocytes. To prevent reduced lymphocyte counts, the U.S. EPA has an established a reference (long-term) concentration for benzene of only 30 ug/m^3.

Mark Chernaik, PhD, interpreted the test results for this project. According to Dr. Chernaik, "The level of benzene in this sample is more than 50% above the U.S. Reference concentration for benzene. If this detected level of benzene in this sample represents ambient air quality that generally prevails at this location, then persons living or attending school at this location would be at risk to adverse impacts to the immune system."[22]

The levels of other aromatics in the sample, – 4-ethyltoluene, 1,3,5-trimethylbenzene, 1,2,4-trimethylbenzene, – although not above health reference levels are strikingly similar to the levels of these aromatics in four other samples and seem to be a fingerprint for volatile organic compounds near an oil and gas facility in this area. The high levels of the tentatively identified compounds propane and butane also strongly suggest that the source of the volatile organic compounds is related to gas field activities.

Matching odors and health effects to sample results

Residents of natural gas production facilities involved in the Bucket Brigade air-testing project recorded their observations and health effects during testing. Once sample results were available, the observed odors and health effects noted in pollution logs were compared to the known health effects of the toxic chemicals found in the samples. Here are several examples:

> *"On Wednesday, Jan 19th air sample was taken at the Blanco, NM Enterprise Buena Vista Compressor Station in Pump Canyon north of several homes. Chris Velasquez and his family live "down wind" of this site. Chris was my guide and companion on the testing trip.*
>
> *I smelled the heavy smell of oily burning plastic. My eyes burned and my nose, throat and mouth became irritated instantly. The soft tissue in my nose, throat and mouth are still sore today as I write this. I have been coughing and my nose is still runny. My eyes are still very red and irritated."*[23]

The sample results confirmed the presence of several noxious benzene compounds, including chlorobenzene, 1, 2, 4-trimethylbenzene and xylene compounds. They are significant irritants to the respiratory system and combined exposure to these could have resulted in the health effects experienced by the sampler.

> *"Warren & I noted additional sharp natural gas/petroleum odors coming from the direction of the BP/CP wells when we did the air sample on January 18th. Warren noted that his eyes were burning. My throat was very irritated and my eyes burned. The musty*

[22] Chernaik, Mark. 25 Jan. 2011
[23] McNall, Shirley. 20 Jan. 2011

> *sewage/feed lot odor is nauseating and causes throat irritation and burning eyes for me.*
>
> *The wells are on BLM land that was granted to the City of Aztec in 1963 for Recreation & Public Use Purposes (R&PP). Some of that land has been granted to Aztec Schools for the new athletic fields and sports complex located about 800 ft. from the wells."*[24]

Sample results from the January 18th sample confirmed the presence of 22 different toxic gases, including cancer-causing benzene. Many of the gases present in the sample irritate the respiratory system and the eyes. Again, the observations recorded by Bucket Brigade air samplers match the sample results.

[24] McNall, Shirley. 20 Jan. 2011

Recommendations

Given the close proximity of residential and public property, any new sites – whether drilling, fracking, refining, or disposal – should be located at least one-quarter mile from homes, farms, schools, playgrounds, and businesses. This space would provide a **buffer zone** for industry to continue its operations while reducing community exposure to chemical contaminants.

U.S. EPA should update air quality standards for oil and gas development, including the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP), based on the following principles:

Comprehensiveness: All sources of air pollution in the oil and gas sector, including exploration, production, processing, transmission, distribution, and storage, and all pollutants released by these sources should be included in any updated air quality regulations, regardless of the level of emissions or major or area source status.

Air monitoring and transparency: Natural gas development sites including well pads, compressors, gas plants, and waste sites should be required to continuously monitor for volatile organic compounds and hydrogen sulfide in order to ensure compliance with regulations, emission limits and public health protections. All data should be publicly available via the web to provide full transparency to the public.

Effectiveness: The EPA should require the best available control technology and require practices and technologies that both reduce air pollution and promote more efficient oil and gas operations.

Full Health Protection: The EPA should consider prohibiting hazardous air pollutant emissions in certain circumstances, and ensure that any residual risk standards reduce lifetime cancer risk from oil and gas operations to below one in one million.

Forward Looking: EPA should develop mechanisms to ensure that any new equipment, facilities, technologies or practices will be subject to air pollution control requirements that may be required under any updated NSPS and NESHAP.

Enforceability: Any standards should be practicably enforceable by including monitoring, record keeping, and reporting requirements necessary to ensure continuous compliance with the standards and to allow the public, States, and the EPA to easily determine deviations and enforce any noncompliance.

CONGRESS should close the gaping loophole in the Clean Air Act's National Emission Standards for Hazardous Air Pollutants (NESHAPs). Oil and gas exploration and production operations are exempt from two key provisions of the NESHAPs, designed to protect public health, allowing the industry to avoid complying with standards that are applied to other industries.

STATES:

In 2009, EPA Administrator Lisa Jackson issued a ruling on a Title V petition holding that states must assess whether oil and natural gas operations should be aggregated in accordance with longstanding EPA policies governing New Source Review and Title V permitting.[25] States should follow the EPA's recent guidance and ensure that emissions from oil and gas operations are appropriately aggregated to ensure compliance with New Source Review and Title V. Aggregation provides an important opportunity to more accurately recognize integrated source operations under the Clean Air Act and ensure that oil and gas operations are regulated on a cumulative basis under New Source Review and Title V.

Until strong new rules are in place, the oil and natural gas industry can and should **voluntarily invest in equipment that reduces pollution escaping to the air**. Such equipment is readily available and financially profitable for companies. These investments would increase efficiency and production and reduce cancer causing chemicals from being emitted into the air in communities near production facilities –saving lives and protecting the health of neighboring families.

As the natural gas industry continues to grow, so will the number of families neighboring and affected by the emissions. Industry and government leaders have a unique opportunity to address public health and environmental issues by implementing these recommendations. For coexistence between communities and industry to be possible, chemical exposure has to be immediately addressed.

[25] http://www.epa.gov/region7/air/title5/t5memos/oilgaswithdrawal.pdf

Pennsylvania Energy Impacts Assessment

Report 1: Marcellus Shale Natural Gas and Wind



Pennsylvania Energy Impacts Assessment

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November 15, 2010

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1. The Nature Conservancy – Pennsylvania Chapter
2. Western Pennsylvania Conservancy – Pennsylvania Natural Heritage Program
3. Audubon Pennsylvania

Cover photos: Marcellus gas drilling rig in Lycoming County © Tamara Gagnolet / TNC; wind turbine in Tioga County © Nels Johnson / TNC; log pile © TNC; electric transmission lines in Clinton County © George C. Gress / TNC

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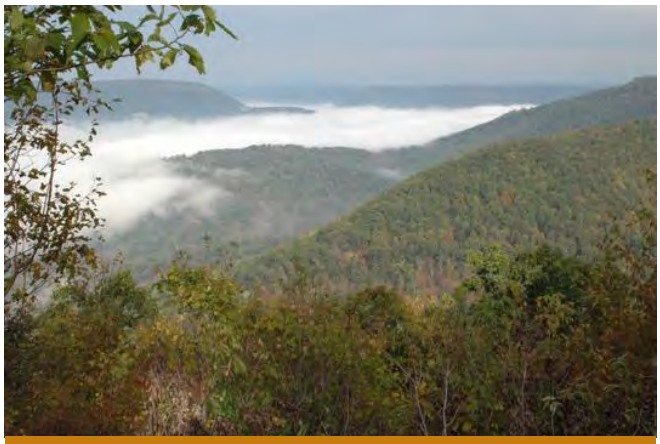
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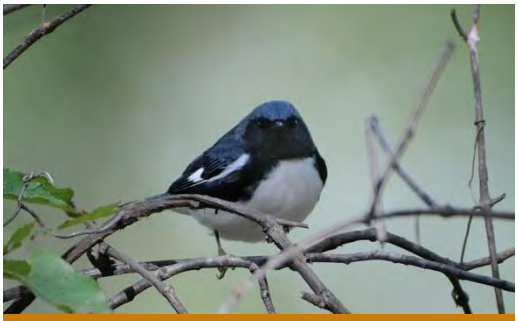
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Executive Summary



Forest landscape along the West Branch Susquehanna River, Clinton County. © George C. Gress / TNC

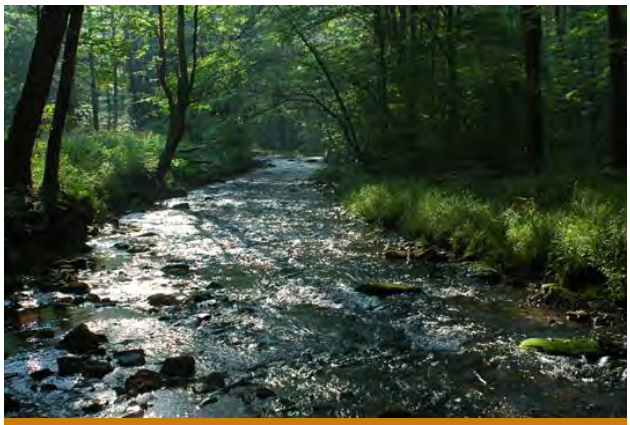
Within a few weeks during the summer of 2000, eight towers rose two hundred feet above an agricultural field on a low ridge top along the Pennsylvania Turnpike. Not long after, large blades began sweeping the Somerset County sky as Pennsylvania's first industrial wind facility went on line. Several years later and an hour drive to the west, an unusual natural gas well was drilled over a mile down and pumped full of water. That well in Washington County yielded a surprising amount of gas flowing from fractures in a shale formation that geologists had long suspected held plenty of gas but has been too expensive to develop. Meanwhile, a Canadian company bought a small sawmill in Mifflintown and started producing wood pellets for stoves, boilers, and electric plants. It soon became one of the region's largest producers of wood biomass energy supplies. In the decade since, these three new energy technologies have expanded rapidly across the state. By the end of this year, 500 wind turbines will be turning on Pennsylvania ridgelines, nearly 2,000 Marcellus natural gas wells will be scattered across rolling fields and forests, and over 50 facilities will be producing wood pellets or burning wood for energy. Thousands of miles of pipelines and powerlines already crisscross the state to get energy supplies to major markets in the Northeast.



Black-throated blue warblers and other interior forest species could be impacted by forest fragmentation caused by energy development. © Gary Irwin

Each of these energy sources carries both promise and risk for people and nature. The promise is that wind, natural gas, and wood biomass energy can reduce greenhouse gas emissions, generate jobs, and increase energy security. The risk is that extensive land use change and loss of natural habitats could accompany new energy development and transmission lines. Impacts to priority conservation habitats across the state have been modest thus far. For example, aerial photo analysis indicates Marcellus gas development has so far cleared just 3,500 acres of forest (about 1,000 acres for wind turbines). An additional 8,500 acres of forest is now within 300 feet of new fragmenting edges created by well pads, and associated roads and infrastructure (5,000 acres for wind turbines). This fragmentation deprives "interior" forest species, such as black-throated blue warblers, northern goshawks, salamanders, and many woodland flowers, of the shade, humidity and tree canopy protection that only deep forest environments can provide.

By all accounts, each of these energy types is likely to grow substantially in Pennsylvania during the next two decades. The Marcellus shale formation, which underlies two-thirds of the state, is now believed to be one of the largest unconventional shale gas reserves in the world. The Pennsylvania Alternative Energy Portfolio Standards Act of 2004, along with state and federal incentives, will likely boost expansion of wind, wood biomass, and other alternative energy types over the next two decades. But, how much of each energy type might be developed? What transmission infrastructure will be needed to get more electric power and natural gas to consumers? And, where are these energy types most likely to be developed? How does the likely scale and location of future energy development overlap with priority conservation areas? The Pennsylvania Energy Impacts Assessment seeks answers to these questions so that conservationists can work more effectively with energy companies and government agencies to avoid, minimize or mitigate habitat impacts in the future.



Nine Mile Run Creek in PA's North Central Highlands
© George C. Gress / TNC.

Assessment Goal: Develop credible energy development projections and assess how they might affect high priority conservation areas across Pennsylvania. Marcellus natural gas, wind, wood biomass, and associated electric and gas transmission lines were chosen as the focus since these energy types have the most potential to cause land-use change in the state over the next two decades. The conservation impacts focus is on forest, freshwater, and rare species habitats. The assessment **does not** address other potential environmental impacts, including water withdrawal, water quality, air quality and migratory pathways for birds and bats. The assessment also does not address a range of other social, economic, and climate characteristics of these energy types.

Key Assumptions: Any assessment of future trends must include certain assumptions. Among the most important assumptions of the Pennsylvania Energy Impacts Assessment are the following:

- A 20-year time period is used to assess potential cumulative habitat impacts from energy development;
- Given uncertainties about how energy prices could change, it was assumed that prices and capital investment (and policy and social conditions) will be sufficient to promote steady development growth for each energy type during the next two decades;
- Given uncertainty about how technology changes could affect spatial footprints, it was assumed that spatial footprints per well pad, turbine, and mile of transmission line will not change significantly during the next two decades;
- Given the proprietary nature of data on leases, Marcellus Shale porosity, fine resolution wind power, etc., all projections are based on publicly available information;
- It was assumed that recent trends and patterns of energy development will continue for the next two decades absent significant changes in government policies and industry practices;

Energy projections contained in this assessment are informed scenarios – **not predictions** – for how much energy development might take place and where it is more and less probable. Projected impacts, however, are based on measurements of actual spatial footprints measured for hundreds of well pads and wind turbines.

Analytical Steps: Key analytical steps for the Pennsylvania Energy Assessment included:

1) *Data collection* – Over 50 spatial data layers on energy resources, development permits, road and transmission infrastructure, physical features, and conservation priorities were compiled for the assessment;

2) *Spatial footprint analysis* – Spatial footprints for Marcellus gas well and wind turbine pads, associated roads, associated pipelines, associated electric transmission lines, and associated other clearings (*e.g.*, gas containment pits, equipment staging areas, electrical substations) were digitized using aerial photos of sites before and after construction;

3) *Scale projections* – Low, medium, and high scenarios for ***how much*** Marcellus Shale natural gas, wind, wood biomass, and transmission line development might occur were based as much as possible on existing projections and data from credible sources.

4) *Geographic projections* – Projections of ***where*** new Marcellus natural gas and wind energy development is more and less likely to occur were based on modeling the probability of a map pixel's land-use change to energy production based on sets of drivers and constraints developed for each energy type. Geographic projections for wood biomass and energy transmission were not modeled due to a lack of data. Conclusions about regional patterns of wood biomass and transmission development and potential conservation impacts will be presented in Report 2 of the Pennsylvania Energy Impacts Assessment.

5) *Conservation impacts analysis* – The potential impacts of future energy development were assessed for forest and freshwater habitats across the state. In addition, sites recognized as important for species of conservation concern were assessed. Conservation datasets for these assessments included, among others, large forest patches from The Nature Conservancy and the Western Pennsylvania Conservancy, habitat areas for rare species from the Pennsylvania Natural Heritage Program, densities for interior forest nesting bird species from the 2nd Pennsylvania Breeding Bird Atlas, and intact watersheds for native brook trout populations from the Eastern Brook Trout Joint Venture.

6) *Review* – A dozen energy experts in government, industry, and research organizations provided technical review of the energy projections.

Energy Projections: The Pennsylvania Energy Impacts Assessment developed low, medium and high scenarios for the amount of energy development that might take place in Pennsylvania by 2030. The projections include:

- *Marcellus Shale* – Sixty thousand wells could be drilled on between 6,000 and 15,000 new well pads (there are currently about 1,000), depending on how many wells are placed on each pad. Gas development will occur in at least half of the state's counties, with the densest development likely in 15 counties in southwest, north central, and northeast Pennsylvania.

- *Wind* – Between 750 and 2,900 additional wind turbines could be built (there are currently about 500), depending on the wind share of electric generation by 2030. Most turbines would be built along the Allegheny Front in western Pennsylvania and on high Appalachian ridgetops in the central and northeastern parts of the state.

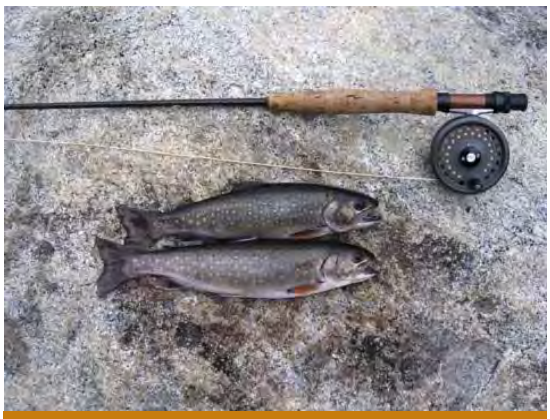
- *Wood Biomass* – Wood biomass energy demand could double or even triple today's wood energy use, depending on whether and how many coal power plants co-fire with wood biomass. Wood biomass energy development is likely to be widespread across the state in all three scenarios.

- *Transmission Lines* – Preliminary findings indicate between 10,000 and 15,000 miles of new high-voltage power lines and gas pipelines (especially gathering lines) could be built during the next twenty years. There is considerable uncertainty about exactly where these lines will be built but recently proposed electric and gas transmission lines provide insights into potential habitat impacts.

Conservation Impacts: This first Pennsylvania Energy Impacts Assessment report focuses on the overlap between likely Marcellus gas and wind development areas and Pennsylvania's most important natural habitats. A second report will focus on the potential for additional impacts from new wood biomass energy plants, electric power lines, and natural gas pipelines. Key findings for impacts from Marcellus natural gas and for wind development include:

Forests. By 2030, a range of between 38,000 to 90,000 acres of forest cover could be cleared by new Marcellus gas development in the state. Forest clearing for the wind development scenarios is much smaller, ranging from 1,900 to 5,200 acres. Such clearings would create new forest edges where the risk of predation, changes in light and humidity levels, and expanded presence of invasive species could threaten forest interior species in 91,000 to 220,000 forest acres adjacent to Marcellus development and 13,400 to 36,000 forest acres adjacent to wind development. Forest impacts will be concentrated in the north central and southwest parts of the state where many of the state's largest and most intact forest patches could be fragmented into smaller patches by well pads, roads, and other infrastructure. Impacts to forest interior species will vary depending on their geographic distribution and density. Some species, such as the black-throated blue warbler, could see widespread impacts to their relatively restricted breeding habitats in the state while widely distributed species, such as the Scarlet Tanager, would be relatively less affected. Locating energy infrastructure in open areas or toward the outer edges of large patches can significantly reduce impacts to important forest areas.

Freshwater. Aquatic habitats are at risk too. Once widespread, healthy populations of native eastern brook trout in Pennsylvania are now largely confined to small mountain watersheds. Nearly 80 percent of the state's most intact brook trout watersheds could see at least some Marcellus gas and wind development during the next twenty years. Strongholds for brook trout are concentrated in north central Pennsylvania, where Marcellus development is projected to be relatively intensive in over half of the state's best brook trout watersheds. Exceptional Value streams – the Department of Environmental Protection's highest quality designation – could see hundreds of well pads (perhaps 300 - 750) and dozens of wind turbines (perhaps 50 – 200) located within one-half mile under the projections. Because many intact brook trout



Brook trout © TNC

and EV streams are in steep terrain, rigorous sediment controls, and possibly additional setback measures, are needed to help conserve these sensitive habitats.

Rare Species. Nearly 40 percent of Pennsylvania's globally rare and Pennsylvania threatened species can be found in areas with high potential for Marcellus gas development. These species tend to be associated with riparian areas, streams, and wetlands, while others are concentrated in unusually diverse areas such as the Youghiogheny Gorge. A handful of rare species have most or all of their known locations in high potential areas for Marcellus gas development. For example, three-fourths of all known snow trillium populations are in high potential Marcellus development areas as are all known populations for the green salamander. A much smaller number of known locations for globally and state rare species overlap with high potential wind development sites and they tend to be associated with rocky outcrops and ridgetop barrens habitats. Species with the greatest overlaps include timber rattlesnakes, Allegheny woodrats, and northern long-eared Myotis bats. More intensive surveys for globally rare and state critically endangered species in high potential Marcellus and wind development areas could help to minimize impacts before development begins. The Pennsylvania Game Commission is working with wind companies and other researchers to assess impacts to migratory pathways for birds and bats.

Recreation. Extensive overlaps are projected between Marcellus development and state forests, state parks, and state game lands. Just over ten percent of Pennsylvania's public lands are legally protected from gas development, most of it within State Wild and Natural Areas or in state parks where the Commonwealth owns the mineral rights. The state does not own mineral rights for 80% of State Park and State Game Lands, nearly 700,000 acres of State Forests have already been leased, and only about 300,000 acres of the remaining State Forest Lands are legally off-limits to future leases. Projections indicate between 900 and 2,200 well pads could be developed across all state lands, with most going on State Forest Lands, followed by State Game Lands, and State Parks. Wind development was not projected on state lands, though some facilities are projected near highly visited sites, including natural vistas.

Clearly, the heart of some of Pennsylvania's best natural habitats lies directly in the path of future energy development. Integrating information on conservation priorities into energy planning, operations, and policy by energy companies and government agencies sooner rather than later could dramatically reduce these impacts. Many factors – including energy prices, economic benefits, greenhouse gas reductions, and energy independence – will go into final decisions about where and how to proceed with energy development. Information about Pennsylvania's most important natural habitats should be an important part of the calculus about trade-offs and optimization as energy development proceeds. Would Pennsylvania's conservation pioneers, including Gifford Pinchot, Maurice Goddard, and Rachel Carson, expect anything less?

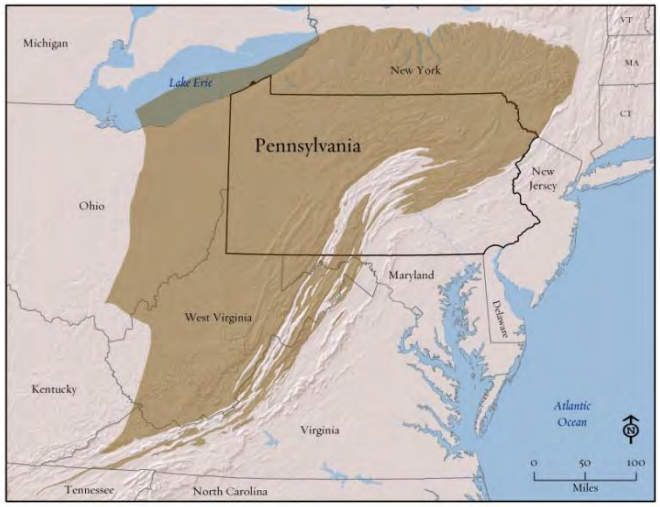
Marcellus Shale Natural Gas

Once thought to be inaccessible, deep shale formations with tightly held natural gas have become the most rapidly growing source of energy in North America. New technologies and methods have allowed companies to drill 6,000 to 10,000 feet down to reach the Marcellus shale, turn the well horizontally to follow the shale layer for a mile or more, and then pump in millions of gallons of water to fracture the shale and release the natural gas. Pennsylvania is at the epicenter of the Marcellus formation, one of the world's largest unconventional shale natural gas reserves. Situated right next door to huge markets in the Mid-Atlantic and Northeastern states, Marcellus gas development has expanded at a furious pace since the first wells were drilled just few years ago in Washington County. There are now approximately 2,000 drilled wells, most of them concentrated in the southwestern and northeastern parts of the state.

The Marcellus boom is bringing rapid economic growth to many rural communities that have been in economic decline for decades. Natural gas is also displacing higher carbon coal and oil supplies thus slowing the rise in greenhouse gas emissions. These benefits are real but not without costs. Large amounts of water must be withdrawn to frac each well (about 5 million gallons). The return flow water that comes back up from the well contains varying levels of chemicals, heavy metals, and even radioactive materials, and must be handled carefully to avoid spills when recycled or disposed. Heavy trucks and compressor stations rumble constantly in gas development areas putting heavy strains on roads, bridges and air quality. Because of known and perceived risks to environmental quality and human health, water use, air emissions and transportation demands are receiving growing attention from government agencies, researchers and energy companies. Thus far, relatively little attention, however, has been focused on Marcellus gas development impacts to natural habitats across the state.

What is Marcellus Shale Natural Gas?

The Marcellus is the largest gas-bearing shale formation in North America in both area and potential gas volume. It spans over 150,000 square miles across 5 states including the southern tier of New York, the northern and western half of Pennsylvania, the eastern third of Ohio, most of West Virginia, and a small slice of western Virginia. Estimates of the potential recoverable volume have increased steadily. The latest estimates by the U.S. Department of Energy are nearly 300 trillion cubic feet – enough to supply all natural gas demand in the United States for at least 10 years.



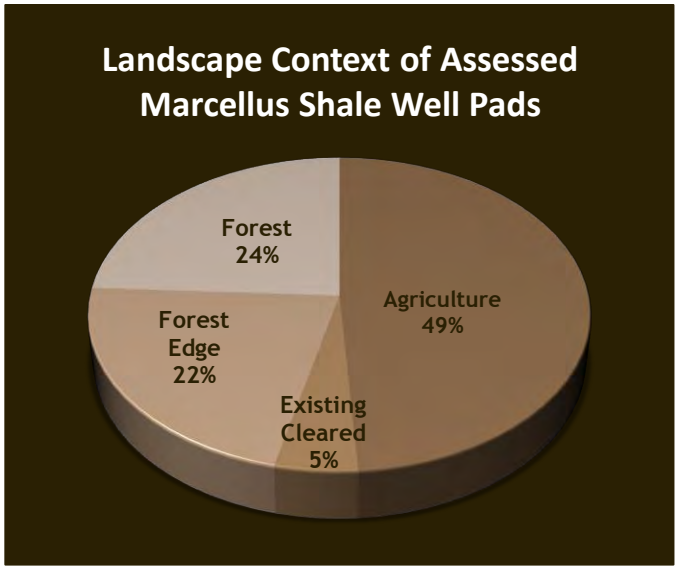
Map showing the extent of the Marcellus Shale formation. Data source: United States Geological Survey.

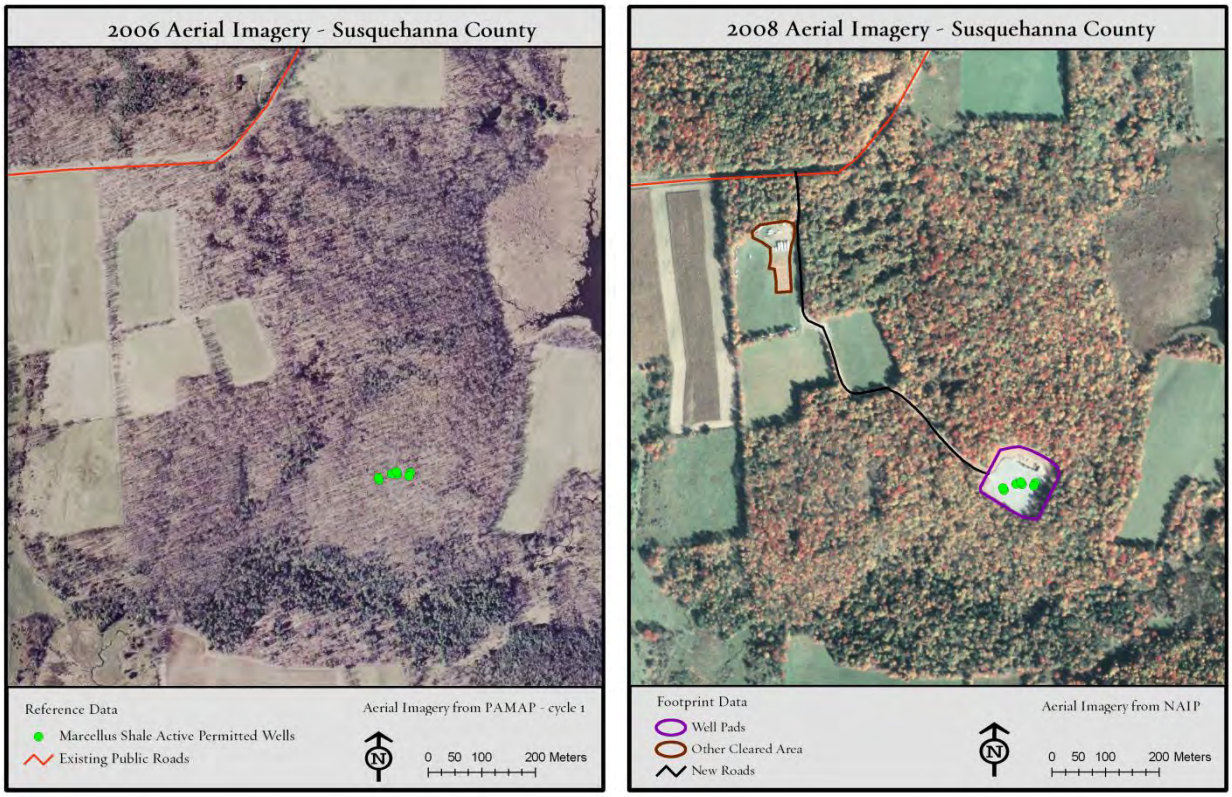
Geologists have long known the Marcellus formation is an organically-rich shale with potentially large amounts of natural gas, but it was too deep, too thin, and too dense to exploit. In 2005, Range Resources drilled the first production Marcellus well using horizontal drilling and hydraulic fracturing methods. The horizontal drilling is necessary because the shale is typically thin and vertical wells will only intercept a small part of the formation. Hydraulic fracturing (or "fracing") is a process that uses large volumes of water, sand, lubricants, and other chemicals to create small fissures in the shale rock. Hydro-fracing is necessary to release the gas which is tightly held in the dense black shale. These methods, first perfected for deep shale gas in the Barnett formation of Texas, unlocked the tremendous gas reserves in the Marcellus and other "unconventional" shale formations previously thought to be out of economic reach.

In contrast to shallow gas deposits in western Pennsylvania, the Marcellus is developed with multiple horizontal wells that can reach out 5,000 feet or more from one well pad. Everything about Marcellus development is bigger than conventional shallow gas plays. The well pads are more expansive (averaging just over 3 acres compared to a small fraction of an acre), the water used to frac wells is much greater (5 million gallons versus a hundred thousand gallons), and the supporting infrastructure is much larger in scale (24" diameter pipelines to gather gas from wells versus 2" or 4" pipelines in shallow fields). Individual wells are also vastly more productive (5 – 10 million cubic feet per day versus less than 100,000 cubic feet in peak early production). While the larger pad, greater water use, and more extensive infrastructure pose more challenges for conservation than shallow gas, the area "drained" by wells on each Marcellus pad is much larger than from shallow gas pads (500-1,000 acres versus 10-80 acres) since there are typically multiple lateral wells on a Marcellus pad versus a single vertical well on a shallow gas pad. The lateral reach of Marcellus wells means there is more flexibility in where pads and infrastructure can be placed relative to shallow gas. This increased flexibility in placing Marcellus infrastructure can be used to avoid or minimize impacts to natural habitats in comparison to more densely-spaced shallow gas fields.

Current and Projected Marcellus Shale Natural Gas Development

Projections of future Marcellus gas development impacts depend on robust spatial measurements of existing Marcellus well pads and infrastructure. By comparing aerial photos of Pennsylvania Department of Environmental Protection (DEP) Marcellus well permit locations taken before and after development, we precisely documented the spatial foot print of 242 Marcellus well pads (totaling 435 drilling permits) in Pennsylvania visible in 2008 aerial imagery from the National Agriculture Imagery Program. The ground excavated for wells and associated infrastructure is the most obvious spatial impact. For each well site, areas cleared for the well pad, new or expanded roads, gathering pipelines, and water impoundments were digitized and measured.





Aerial photos before and after development of a Marcellus gas well pad site in Susquehanna County, PA. To assess the impacts of this type of energy development, we digitized the spatial footprint of 242 gas well pad sites and associated infrastructure.

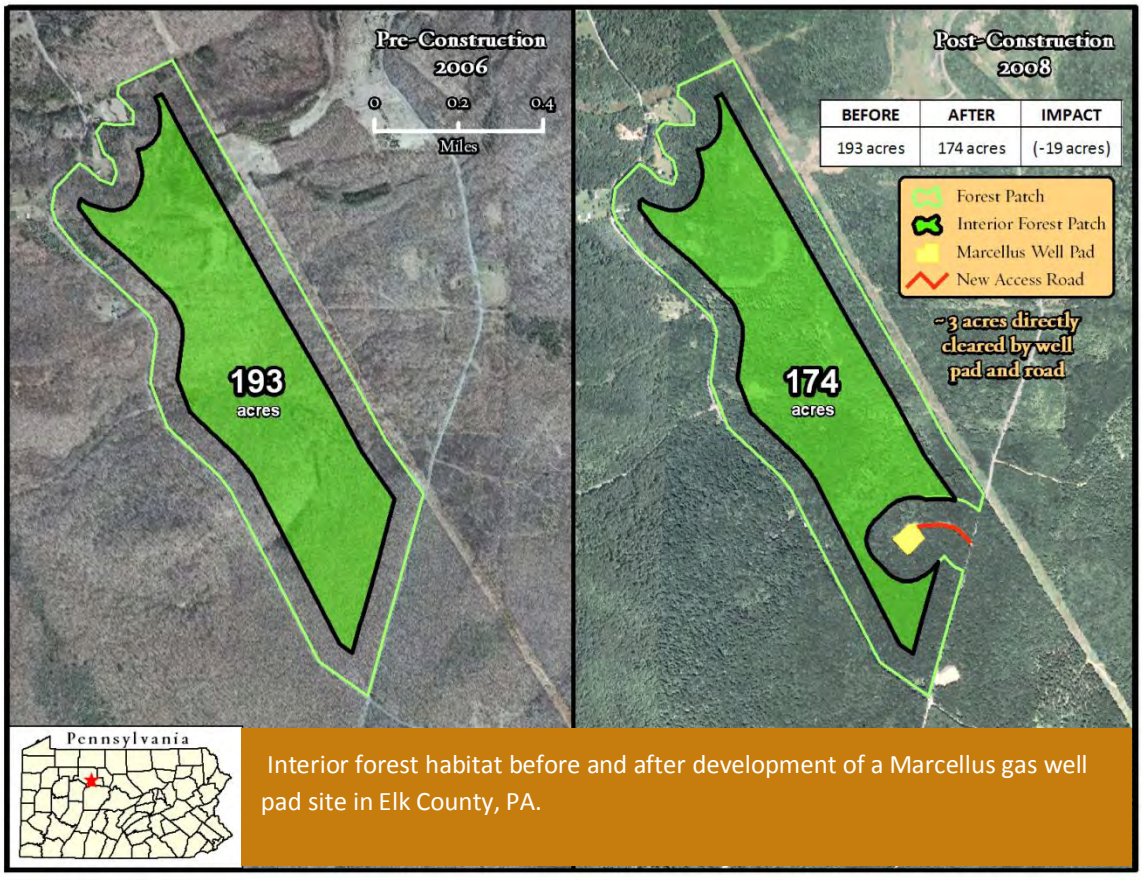
Average Spatial Disturbance for Marcellus Shale Well Pads in Forested Context (acres)		
Forest cleared for Marcellus Shale well pad	**3.1**	**8.8**
Forest cleared for associated infrastructure (roads, pipelines, water impoundments, etc.)	**5.7**	
Indirect forest impact from new edges	**21.2**	
TOTAL DIRECT AND INDIRECT IMPACTS	**30**	

Well pads occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad.

Adjacent lands can also be impacted, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on “interior” forest conditions.

Forest ecologists call this the “edge effect.” While the effect is somewhat different for each species, research has shown measurable impacts often extend at least 330 feet (100 meters) forest adjacent to an edge. Interior forest species avoid edges for different reasons. Black-throated blue warblers and other interior forest nesting birds, for example, avoid areas near edges because of the increased risk of predation. Tree frogs, flying squirrels and certain woodland flowers are sensitive to forest fragmentation because of changes in canopy cover, humidity and light levels. Some species, especially common species such as whitetail deer and cowbirds, are attracted to forest edges – often resulting in increased competition, predation, parasitism, and herbivory. Invasive plant species, such as tree of heaven, stilt grass, and Japanese barberry, often thrive on forest edges and can displace native forest species. As large forest patches become progressively cut into smaller patches, populations of forest interior species decline.

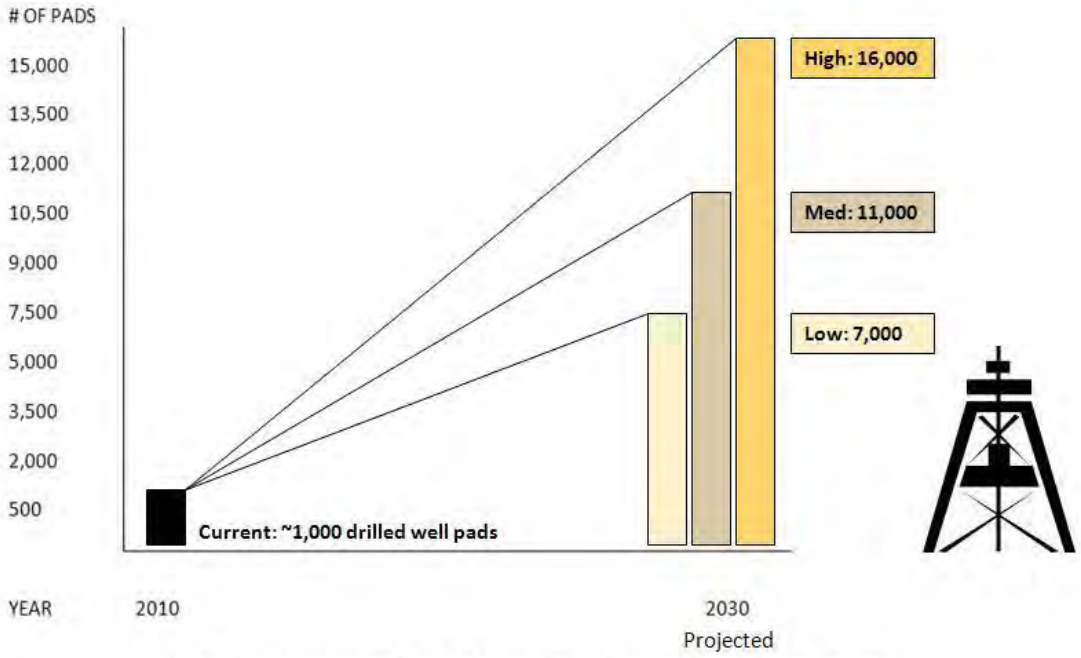
To assess the potential interior forest habitat impact, we created a 100 meter buffer into forest patches from new edges created by well pad and associated infrastructure development. For those well sites developed in forest areas or along forest edges (about half of assessed sites), an average of 21 acres of interior forest habitat was lost.



Interior forest habitat before and after development of a Marcellus gas well pad site in Elk County, PA.

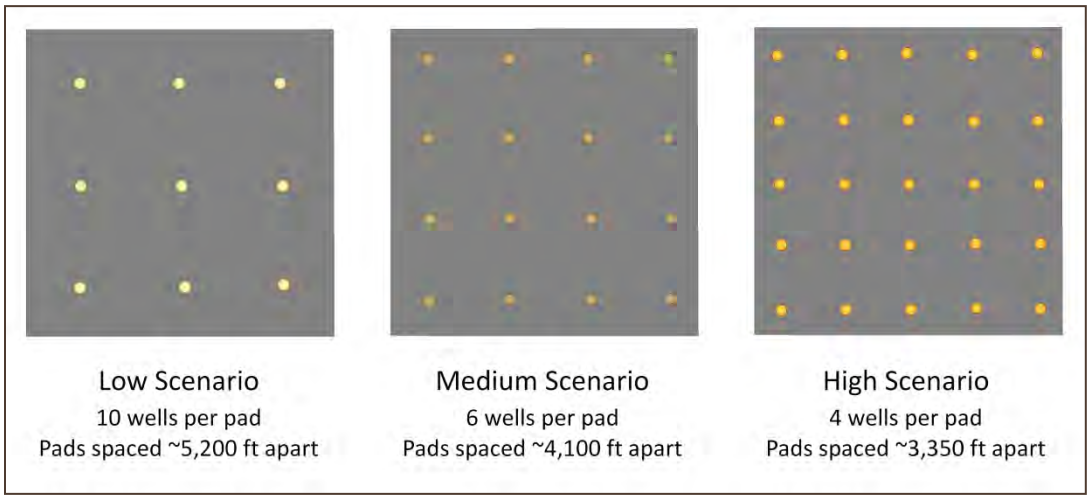
The number of Marcellus wells drilled in Pennsylvania during the next two decades will expand steadily. Just how many wells are drilled will be driven by various factors including natural gas prices, technological improvements, human resources, regulatory changes in Pennsylvania and beyond (e.g., end of New York drilling moratorium), and social preferences. Assessing how these factors will change over the next two decades is very difficult; therefore our projections assume economic, policy, and social conditions remain stable enough to promote steady expansion of Marcellus gas development in the state. The first key variable in our projection is the number of drilling rigs that

will be operating in Pennsylvania. By October 2010, the industry had moved just over 100 rigs into Pennsylvania to drill Marcellus wells according to the Baker-Hughes weekly rig count. Given the high productivity of the Marcellus and its proximity to major northeastern markets, most industry observers expect this number to continue growing steadily. The number of horizontal drill rigs operating in the Barnett Shale has peaked at about 200, but the



Key drivers: number of rigs, number of wells per pad.

We project 60,000 Marcellus wells will be drilled during the next twenty years based on company investor presentations and academic assessments of gas development potential. Depending on how many wells on average are placed on the same pad site (see illustration below), we project between 7,000 and 16,000 total well pad sites will be developed in Pennsylvania by 2030.



Marcellus Shale is much larger and could reach 300 rigs in Pennsylvania alone. We chose a conservative estimate of 250 maximum horizontal drill rigs for each scale projection scenario. Assuming that each rig can drill one well per month, 3,000 wells are estimated to be drilled annually. At that rate, 60,000 new wells would be drilled by the year 2030.

The second key variable, especially for determining land-use and habitat impacts, is the number of wells on each pad. Because each horizontal well can drain gas from 80 to 170 acres (depending on the lateral well length), more wells per pad translates to less disturbance and infrastructure on the landscape. It is technically possible to put a dozen or more Marcellus wells on one pad. So far, the average in Pennsylvania is two wells per pad as companies quickly move on to drill other leases to test productivity and to secure as many potentially productive leases as possible (leases typically expire after 5 years if there is no drilling activity). In many cases, the gas company will return to these pads later and drill additional wells. The low scenario (6,000 well pads) assumes that each pad on average will have ten wells. Because many leases are irregularly shaped, in mixed ownership, or the topography and geology impose constraints, it is unlikely this scenario will develop. It would take relatively consolidated leaseholds and few logistical constraints for this scenario to occur. The medium scenario for well pads assumes 6 wells on average will be drilled from each pad, or 10,000 new well pads across the state. Industry staff generally agree that six is the most likely number of wells they will be developing per pad for most of their leaseholds, at least where lease patterns facilitate drilling units of 600 acres or larger. The high scenario assumes each pad will have 4 wells drilled on average, or 15,000 well pads across the state. This scenario is more likely if there is relatively little consolidation of lease holds between companies in the next several years.

The number of well pads is less important than where they are located, at least from a habitat conservation perspective. To understand which areas within Pennsylvania's Marcellus formation are more and less likely to be developed, we used a machine-based learning modeling approach known as maximum entropy (Maxent 3.3.3a, Princeton University). Maximum entropy was used to find relationships between 1,461 existing and permitted well pad locations and variables that might be relevant to a company's decision to drill a Marcellus well. Such variables were chosen based on data availability and included Marcellus Shale depth, thickness and thermal maturity as well as percent slope, distance to pipelines, and distance to roads. The model produces a raster surface that represents the probability of an area to potentially support future gas well development. An additional 487 existing and permitted well pads were used to test the validity of the model's probability surface and the model was found to be 80% accurate in predicting existing and permitted wells from randomly sampled undeveloped areas. The resulting probability map indicates wide variation across the Marcellus formation in terms of the likelihood of future gas well development.

To get a better sense of where gas development is most likely, we searched for the highest probability areas where well pads in each scenario might be located. The probability raster was re-sampled to a resolution that reflects the minimum separation distance between well pads for each of the three impact scenarios (low – 1,590 m; medium – 1,260 m; high – 1,020 m). The minimum separation distance depends on the number of wells drilled per pad and accounts for the average gas drainage area assumed for each of the three scenarios. Areas incompatible for future gas exploration (existing drilled Marcellus Shale wells, Pennsylvania State Wild Areas and Natural Areas, and water bodies) were excluded from being selected as probable pixels. For each scenario, the highest probable pixels were selected until the pad threshold was reached (low – 6,000 well pads; medium – 10,000 well pads; high – 15,000 well pads). The highest probable pixels were then converted into points for map display purposes.

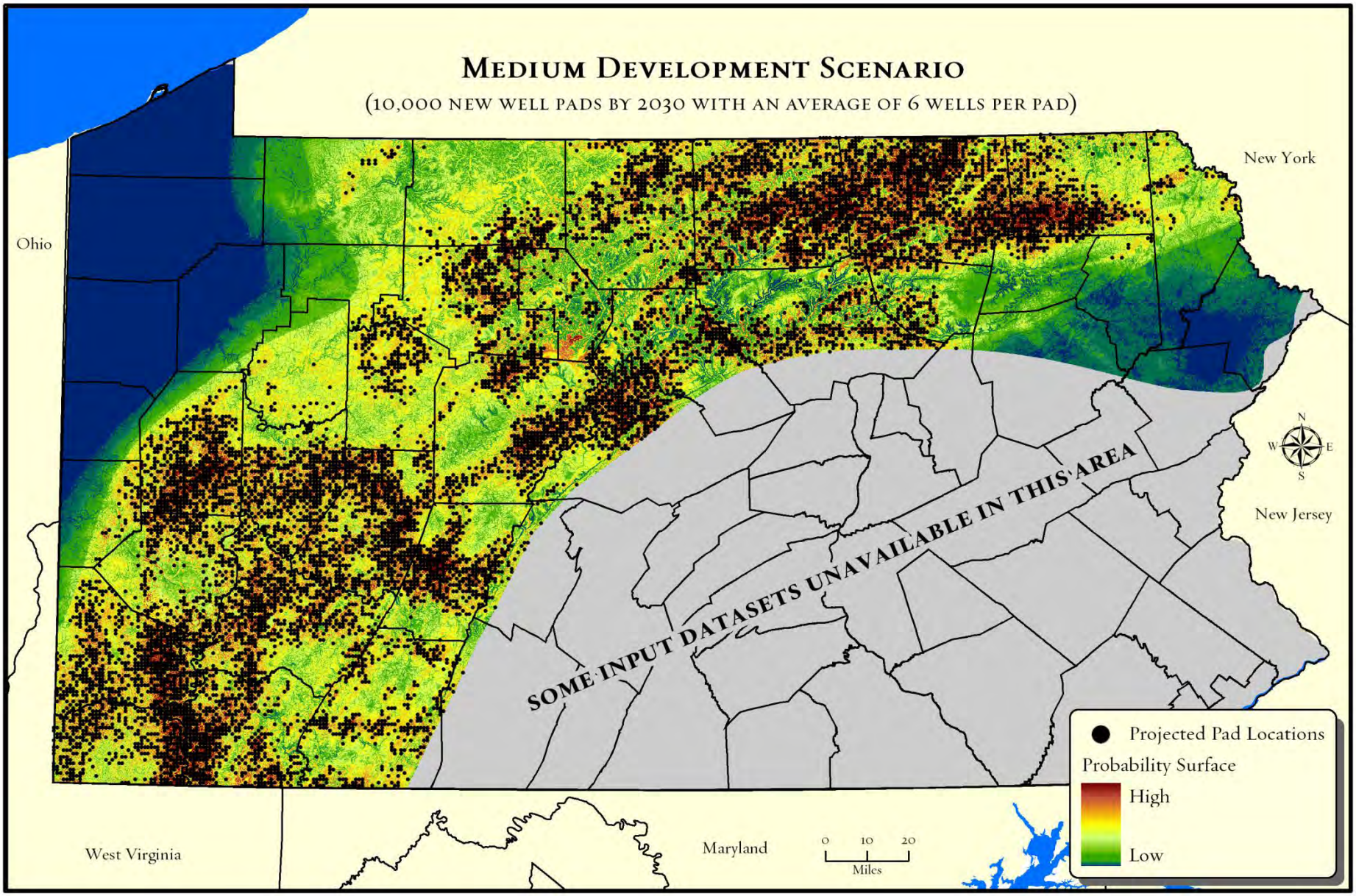
While the geographic area with projected well pads expands from low to high scenarios, the overall geographic pattern is not cumulative due to the differences in minimum separation distance between the three scenarios. Overall, hotspots for future gas development can be seen in half a dozen counties in southwestern Pennsylvania and half a dozen counties in north central and northeastern parts of the state.

These geographic projections of future Marcellus gas development are spatial representations of possible scenarios. They are not predictions. We faced several constraints in developing the geographic scenarios:

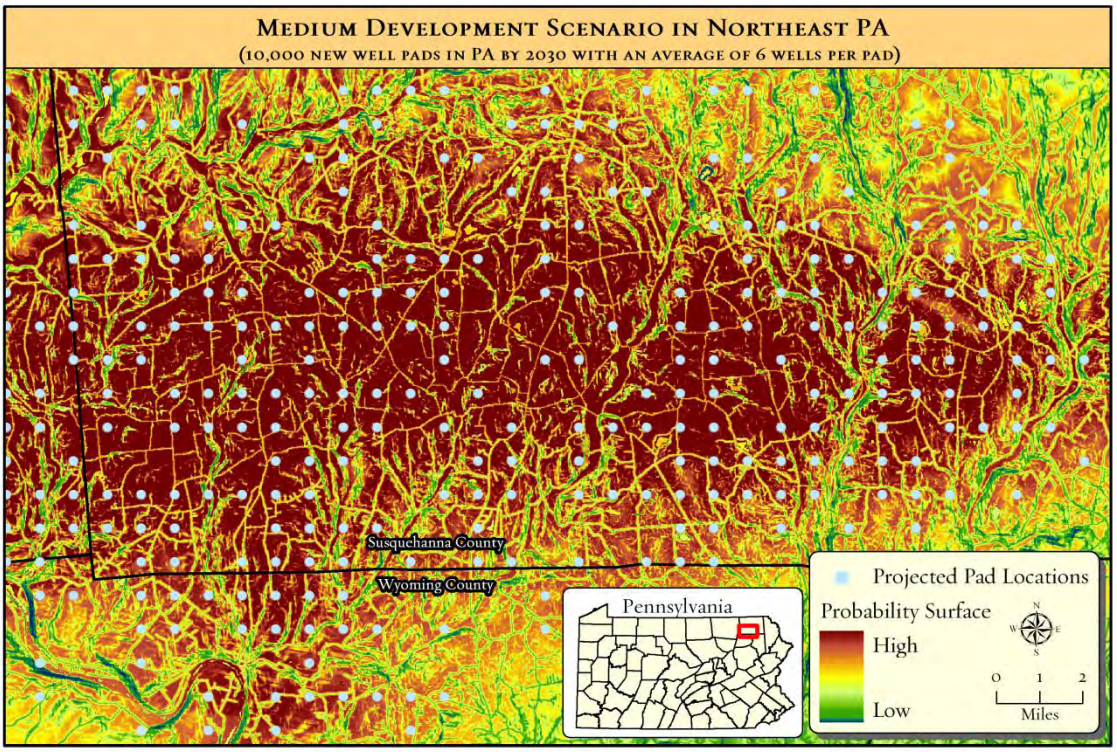
- We do not have access to proprietary seismic and test well geologic data that natural gas companies have. Shale porosity, for example, is a key factor but there are no publicly available data for this.

- We do not have the detailed location of gas company leases. Each company is looking for the highest probability locations across their lease holds while our model looks for the highest probability sites across the entire Marcellus formation in the state. Because there have only been a few Marcellus test wells and permits in the Delaware watershed, we believe the projections for new well pads are probably significantly underestimated in Wayne County.

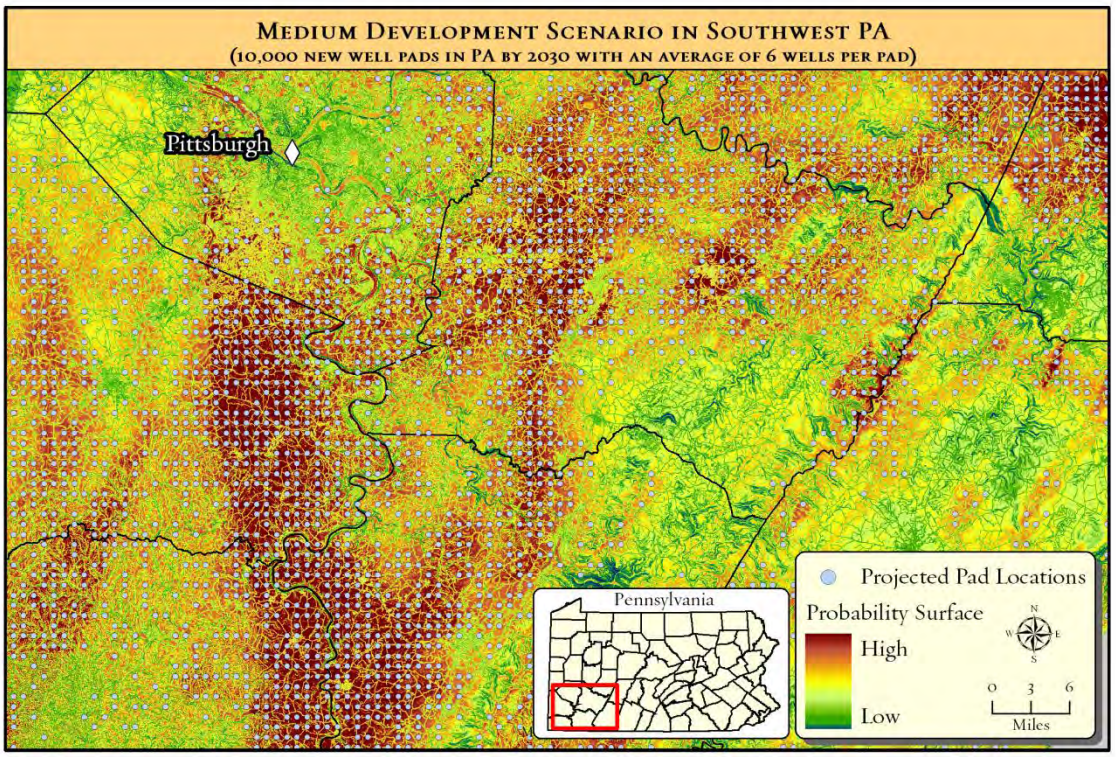
Still, we believe the overall geographic patterns in the projected gas development locations are relatively robust for several reasons. We used nearly 1,500 existing drilled or permitted well pads to build the model and nearly 500 additional drilled and permitted well pads to validate the model. These unique well pad locations represented 4,446 permitted wells. This is typically a sufficient sample size for building predictive models. Additionally, reviews from industry, academic, and government agency reviewers indicate our methods and results are generally sound. Some reviewers expect future well pad locations to be more geographically expansive than our current projections indicate, especially in the Delaware watershed where only a few Marcellus test wells and permits have been issued. Our projections for Wayne County, for example, are likely underestimating future development potential.



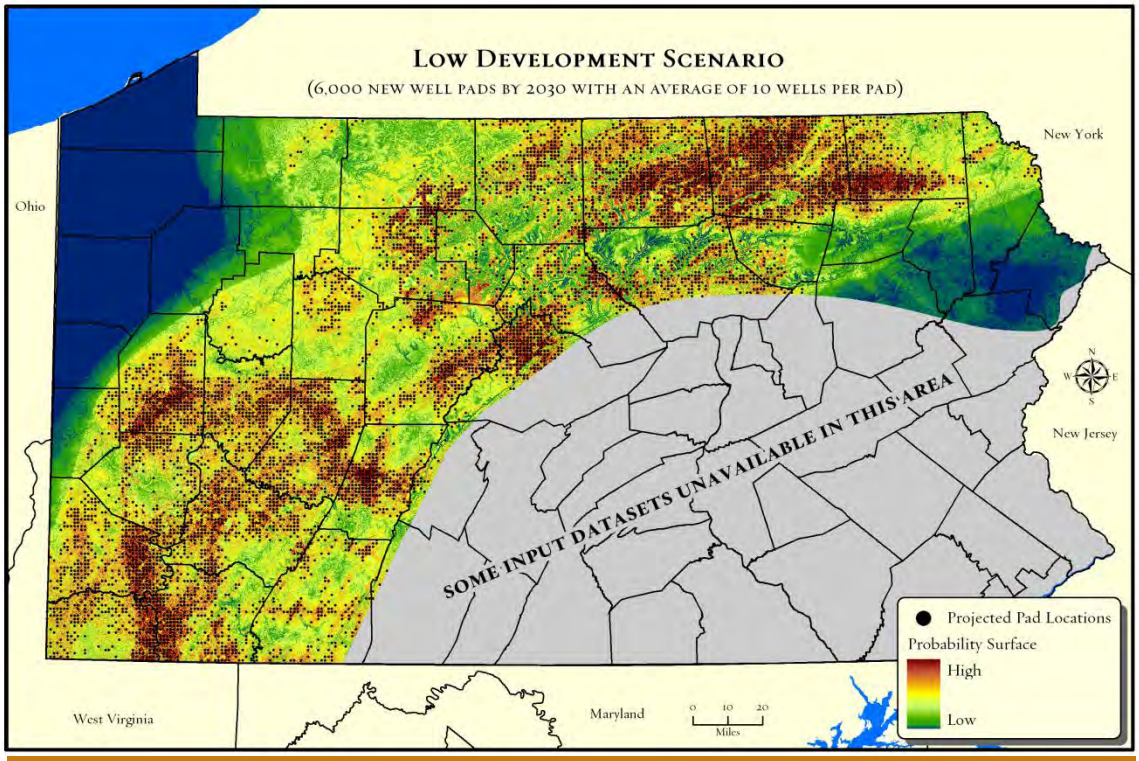
Map showing projected location of 10,000 new Marcellus Shale natural gas pads across Pennsylvania (medium development scenario).



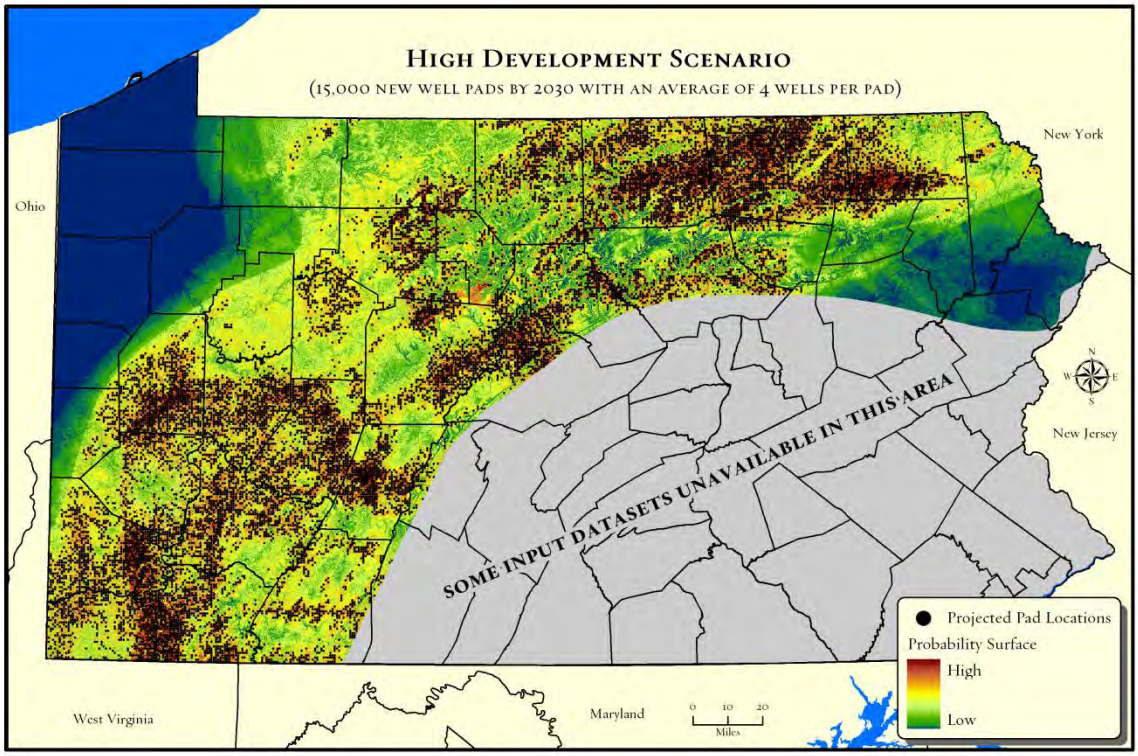
Map showing projected location of new Marcellus well pads in southern Susquehanna County under the medium development scenario.



Map showing projected location of new Marcellus well pads in southwestern Pennsylvania under the medium development scenario.



Map showing projected location of 6,000 new Marcellus well pads across Pennsylvania (low development scenario).



Map showing projected location of 15,000 new Marcellus well pads across Pennsylvania (high development scenario).

Conservation Impacts of Marcellus Shale Natural Gas Development

What is the overlap of the areas with the highest probability of future Marcellus gas development and those areas known to have high conservation values? To answer this question, we intersected the projected Marcellus well pads with areas previously identified and mapped as having high conservation values. We looked at several examples from four categories of conservation value, including:

- Forest habitats
- Freshwater habitats
- Species of conservation concern
- Outdoor recreation

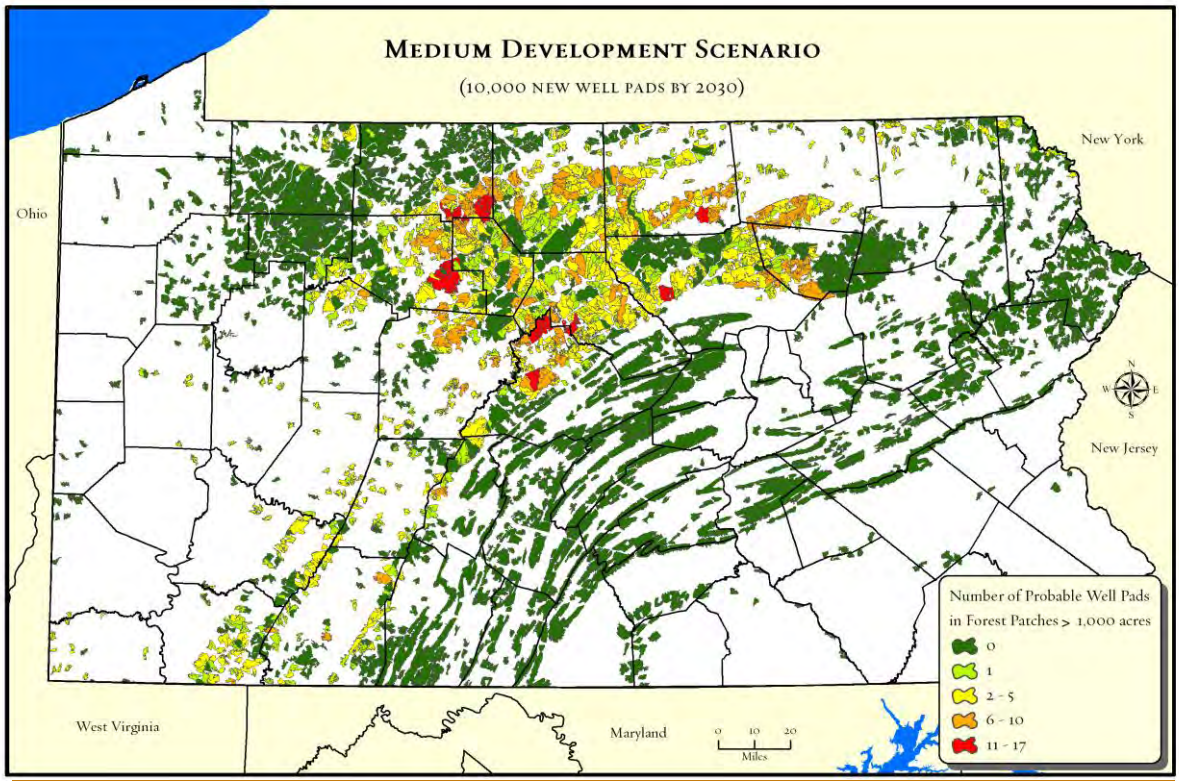
Substantial areas of overlap are indicated between likely future Marcellus development areas and Pennsylvania's most important forest, freshwater, sensitive species habitats, and outdoor recreation sites.

FORESTS

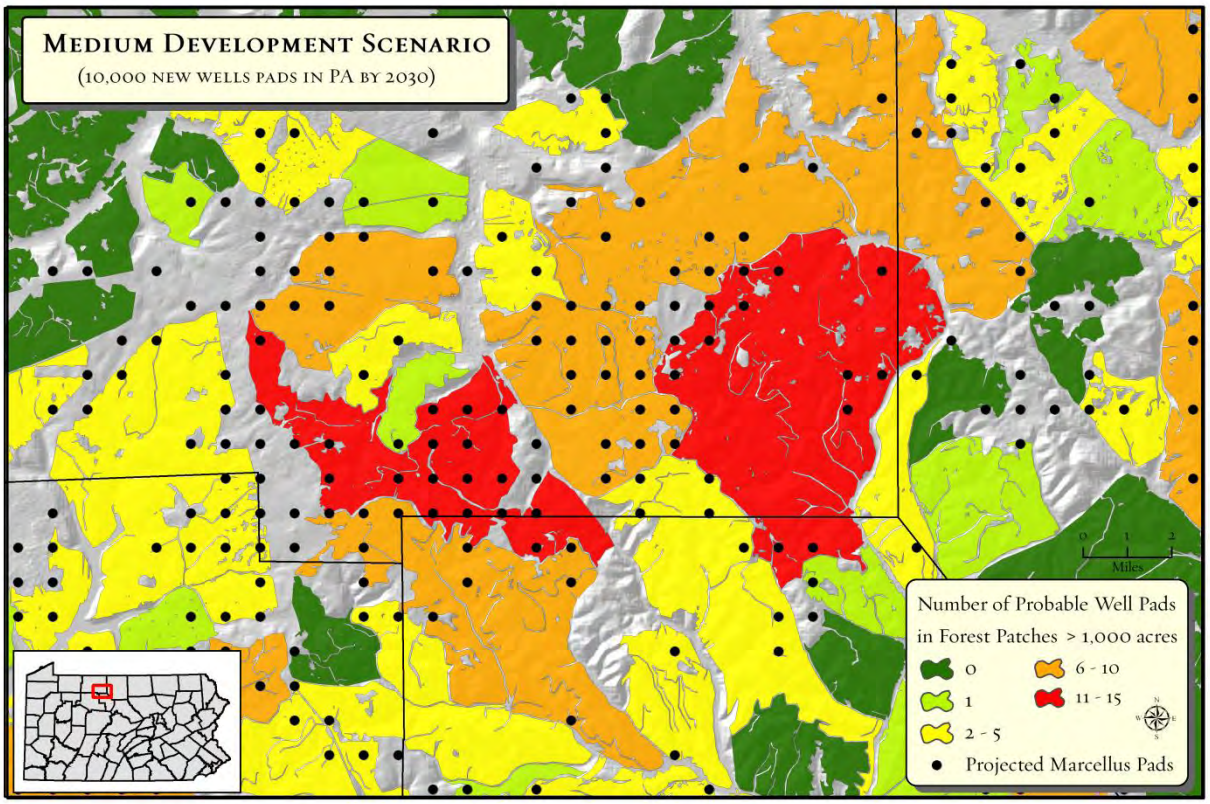
Forests are Pennsylvania's most extensive natural habitat type. Once covering at least 95 percent of the state's land area, forests were whittled away for agriculture, charcoal for iron smelting, and lumber until only a third of the state's forests remained. Forests have rebounded steadily to cover about 60 percent of the state, though a trend toward increasing net loss of forest has emerged during the past decade. Pennsylvania is famous worldwide for its outstanding cherry, oak, and maple hardwoods, and forests provide livelihoods for many thousands of Pennsylvanians in the forest products and tourism industries. They also contribute enormously to the quality of life for all Pennsylvanians by filtering contaminants from water and air, reducing the severity of floods, sequestering carbon dioxide emissions that would otherwise warm the planet, and providing a scenic backdrop to recreational pursuits.

A majority of projected well locations are found in a forest setting for all three scenarios (64% in each case). The low scenario would see 4,310 well pads in forest areas. With an average cleared forest average of 8.8 acres per pad (including roads and other infrastructure), the total forest clearing would be approximately 38,000 acres. Indirect impacts to adjacent forest interior habitats would total an additional 91,000 acres. Forest impacts from the medium scenario (6,950 projected wells in forest locations) would be 61,000 cleared forest acres and an additional 147,000 acres of adjacent forest interior habitat impacts. For the high scenario (10,250 forest well pads), approximately 90,000 acres would be cleared, and an additional 220,000 acres of forest interior habitats would be affected by new adjacent clearings. While the high Marcellus scenario would result in a loss of less than one percent of the state's total forest acreage, areas with intensive Marcellus gas development could see a loss of 2-3 percent of local forest habitats. Some part of the cleared forest area will become reforested after drilling is completed, but there has not been enough time to establish a trend since the Marcellus development started.

Large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, such as northern goshawk, and provide more habitat for forest interior species. They are also more resistant to the spread of invasive species, suffer less tree damage from wind and ice storms, and provide more ecosystem services – from carbon storage to water filtration – than small patches. The Nature Conservancy and the Western Pennsylvania Conservancy's Forest Conservation Analysis mapped nearly 25,000 forest patches in the state greater than 100 acres. Patches at least 1,000 acres in size are about a tenth of the total (2,700) and patches at least 5,000 acres are rare (only 316 patches). In contrast to overall forest loss, projected Marcellus gas development scenarios indicate a more pronounced impact on large forest patches. For example, 40 percent of patches greater than 5,000 acres are projected to have at least one well pad and associated infrastructure located in them in the medium scenario compared to just over 20 percent for patches > 1,000 acres. Most affected large patches have multiple projected well pads (as many as 29). The projections indicate larger patches are likely to be more vulnerable, with over a third projected to have at least one new well pad and road. Many affected large patches have multiple projected well pads (as many as 17 for patches). While one or two well pads and associated infrastructure may not fragment the large patch into smaller patches, each additional well pad increases the likelihood that the large patch will become several smaller patches with a substantially reduced forest interior habitat area.



Map showing number of probable Marcellus well pads in forest patches greater than 1,000 acres across Pennsylvania.

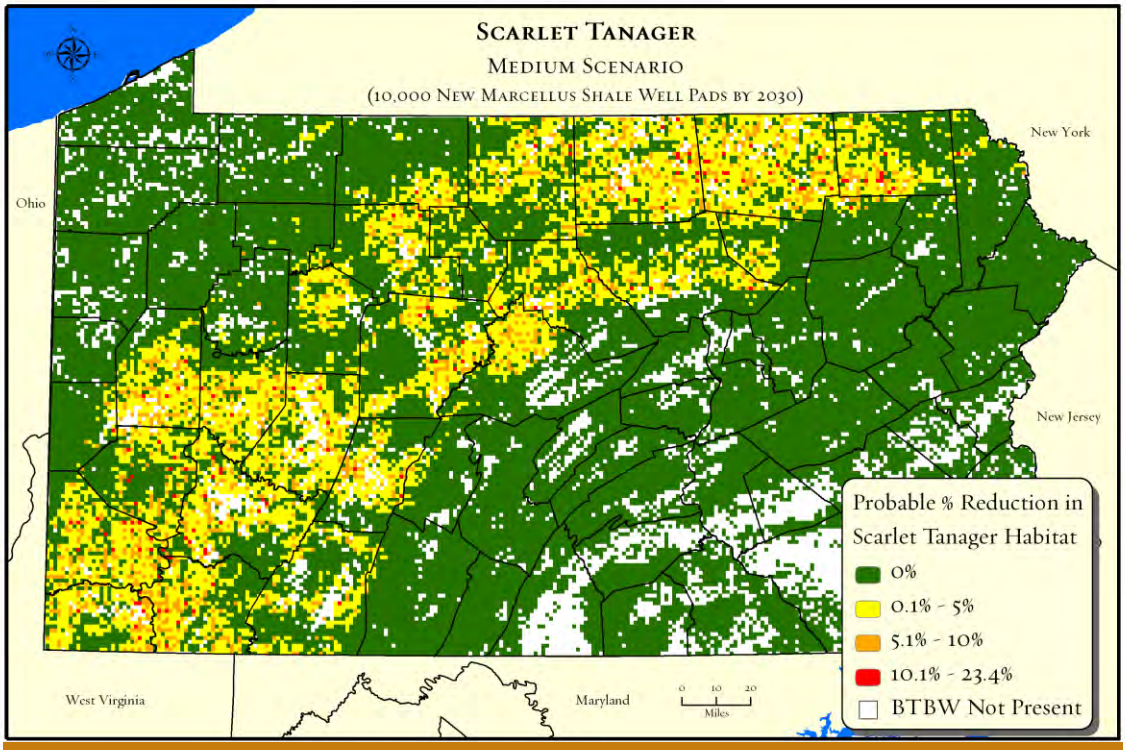


Map showing projected number of well pads in forest patches greater than 1,000 acres under the medium development scenario in Potter, Cameron, McKean and Forest Counties.

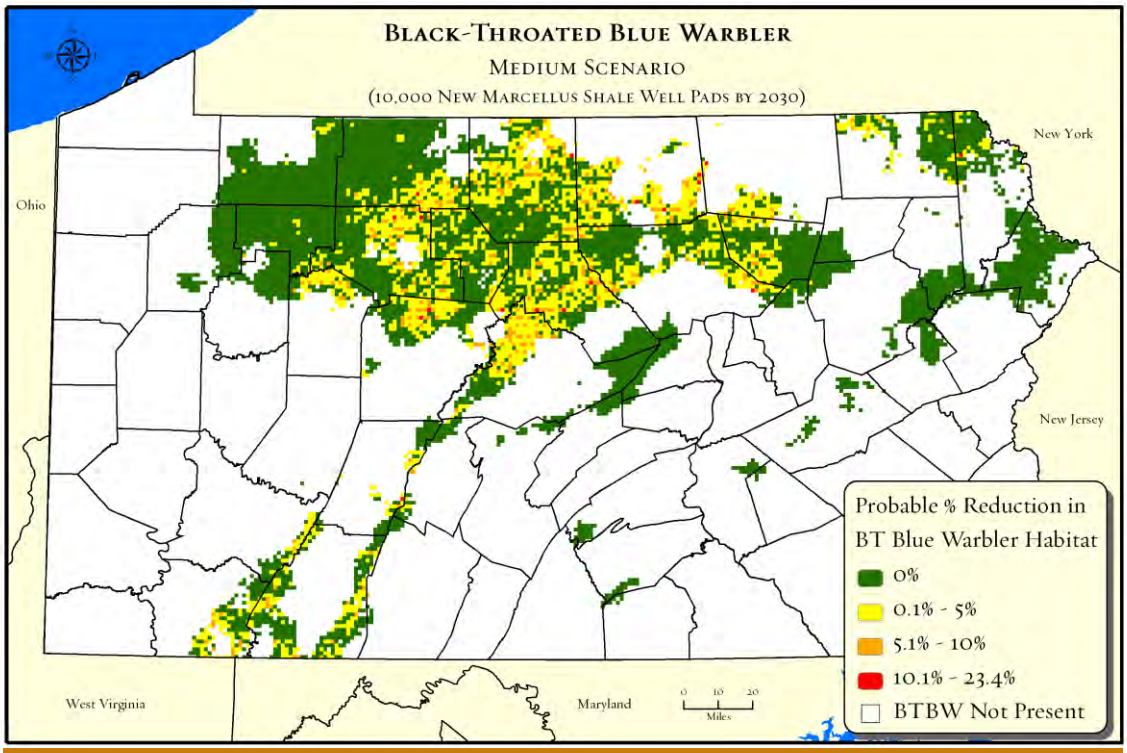
Bird species that nest in close canopy forest environments are often referred to as "forest interior" species. The Carnegie Museum of Natural History, Powdermill Nature Reserve and the Pennsylvania Game Commission recently completed Pennsylvania's Second Breeding Bird Atlas project. As part of the project, trained ornithologists conducted point counts using standardized protocols at 39,000 sites from 2004 to 2009. The result is an incredibly detailed data base that provides the most accurate information on the distribution and density of breeding birds available anywhere in the United States. Density data for several forest interior nesting species were mapped and intersected with the projected Marcellus gas well pad locations. The resulting maps show the estimated reduction in habitat for that species in each Marcellus gas probability pixel (including both cleared forest and adjacent edge effects). Scarlet Tanagers are one of the most widespread forest interior nesting bird in the state. Since they are so widespread, a majority of their range in the state is outside of the most likely Marcellus development areas. In some locations, scarlet tanager populations could decline by as much as 23 percent in the Medium Scenario. Black-throated blue warblers are more narrowly distributed in Pennsylvania favoring mature northern hardwood and coniferous forests with a dense understory, frequently in mountain terrain. Since most of their breeding range in Pennsylvania overlaps with likely Marcellus development areas, a higher proportion of their habitat could be affected.



Scarlet tanager © U.S. Fish and Wildlife Service



Map showing estimated percent loss of habitat for Scarlet Tanagers under medium scenario.

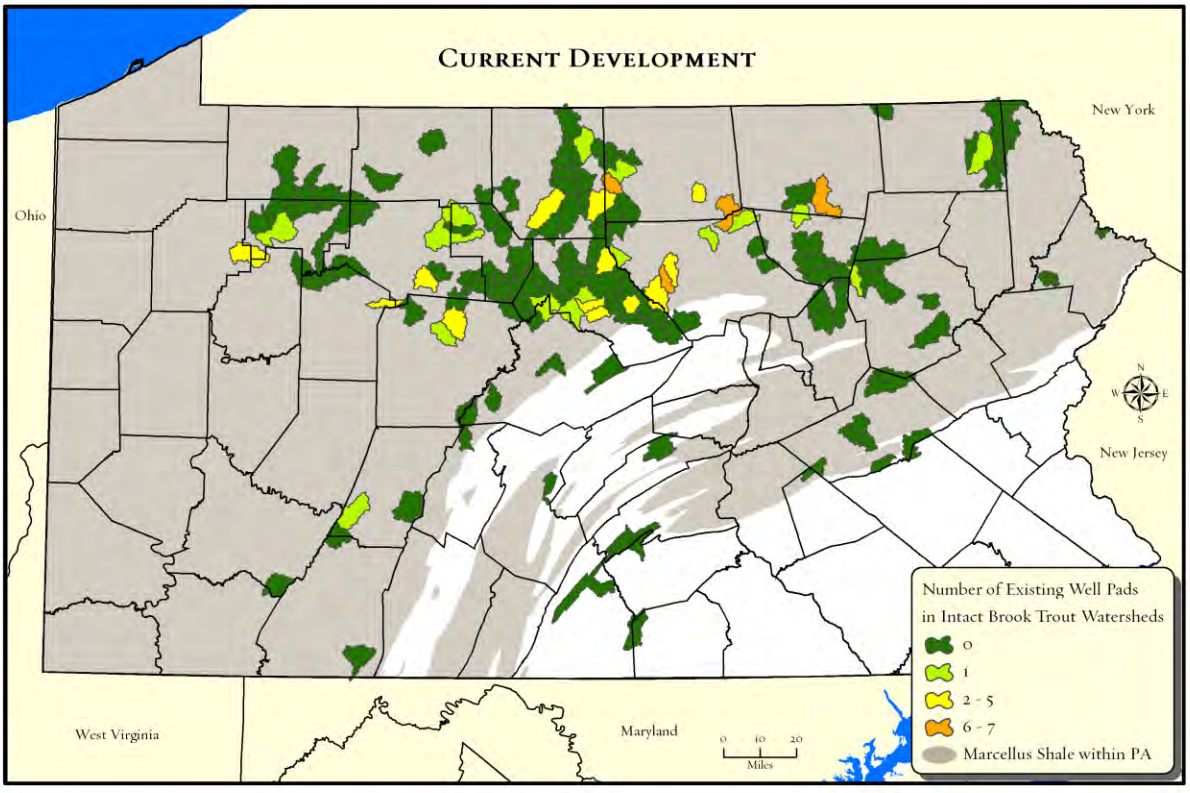


Map showing estimated percent loss of habitat for Black-Throated Blue Warblers under medium scenario.

FRESHWATER

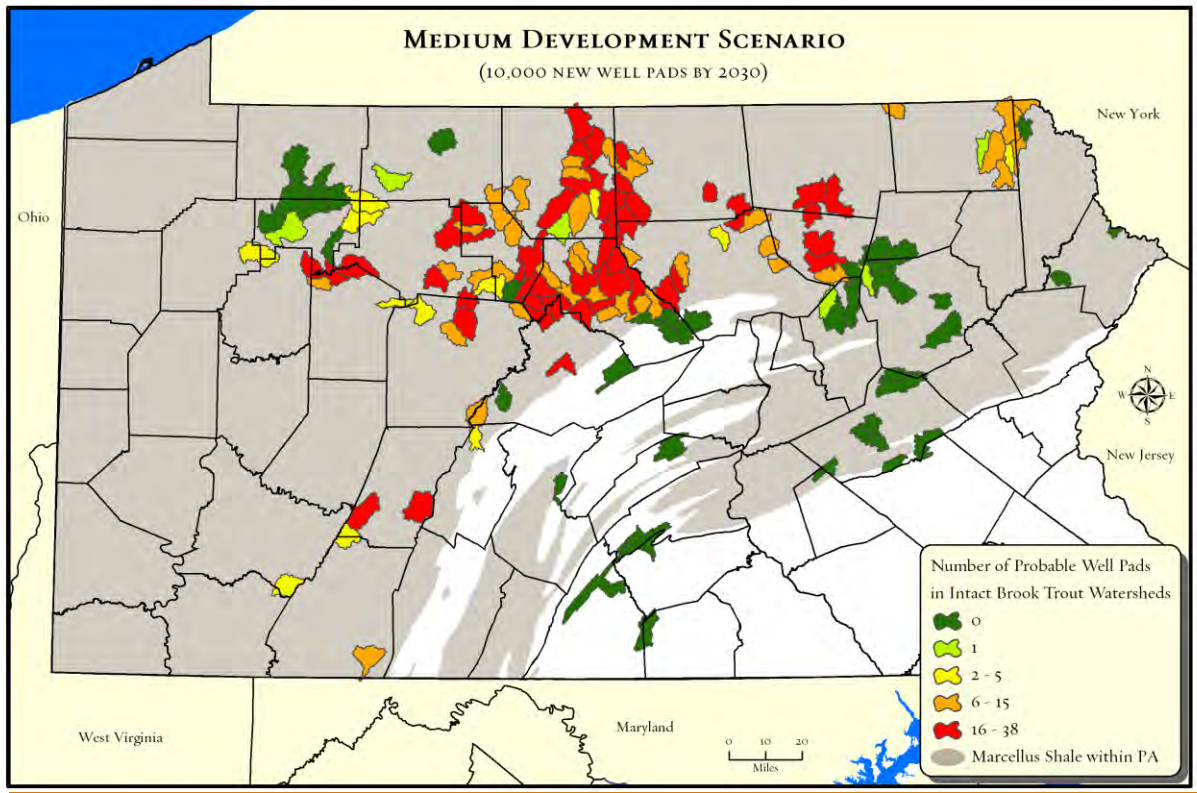
Home to three great river systems and one of the Great Lakes, Pennsylvania's fresh water resources are vital not only to the Commonwealth but to much of the eastern United States. The ***Ohio River*** basin contains the richest fresh water ecosystems in North America. In Pennsylvania, French Creek and parts of the Upper Allegheny River contain some of the most intact aquatic ecosystems in the entire basin. The ***Susquehanna* River** is the source of more than half the fresh water that enters the Chesapeake Bay, and most of the water that flows down the Susquehanna River originates in tributary headwaters across a wide swath of central Pennsylvania. Forming Pennsylvania's eastern boundary, the ***Delaware River*** is the longest undammed river in the eastern United States, one of the last strongholds for Atlantic coast migratory fish, and provides the drinking water source for nearly 20 million Americans living in Pennsylvania, New York, and New Jersey. Because of their importance to human health and livelihoods, the potential of Marcellus gas development to affect water flows and quality have received growing attention from regulatory agencies, natural gas companies, and environmental groups.

The intersection of gas development with sensitive watersheds has received less attention. High Quality and Exceptional Value (EV) watersheds have been designated by the Pennsylvania Department of Environmental



Map showing current number of Marcellus well pads in intact and predicted intact brook trout watersheds. Data source: Eastern Brook Trout Joint Venture.

Protection across the state. Our projections indicate 28 percent of High Quality and 5 percent of Exceptional Values streams have or will have Marcellus gas development during the next two decades. Presence of well pads in these watersheds may not be a problem as long as spill containment measures and erosion and sedimentation regulations are strictly observed and enforced in these areas. More specifically, the projections indicate 3,581 well pads could be located within ½ mile of a High Quality or Exceptional Values streams. Pads within close proximity to High Quality and especially Exceptional Value streams pose more risk than those at greater distances, as there is increased risk for potential spills and uncontained sediments to find their way into streams.



Map showing projected number of Marcellus well pads by 2030 in intact and predicted intact brook trout watersheds under medium scenario. Data source: Eastern Brook Trout Joint Venture.

Native brook trout are one of the most sensitive aquatic species in Pennsylvania watersheds. Brook trout favor cold, highly-oxygenated water and are unusually sensitive to warmer temperatures, sediments, and contaminants. Once widely distributed across Pennsylvania, healthy populations have retreated to a shrinking number of small watersheds. Many of these watersheds overlap with the Marcellus shale formation. A large majority (113) of the 138 intact or predicted intact native brook trout watersheds in Pennsylvania are projected to see at least some Marcellus gas development. Over half (74) are projected to host between 6 – 38 well pads, and the number reaches as high as 64 pads for some intact brook trout watersheds in the high scenario. Rigorous sediment controls and carefully designed stream crossings will be critical for brook trout survival in watersheds, especially upper watersheds, with intensive Marcellus development.

RARE SPECIES

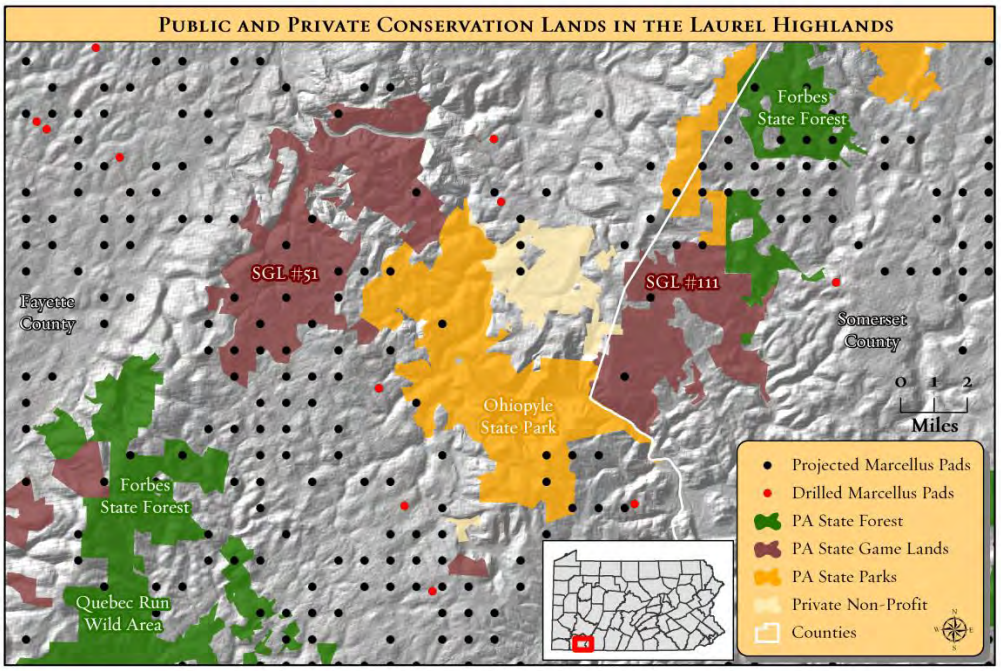


Green salamander © Pennsylvania Fish and Boat Commission

Of the approximately 100,000 species believed to occur in Pennsylvania, just over 1 percent (1052) is tracked by The Pennsylvania Natural Heritage Program (PNHP). Due to low population sizes and immediate threats, these species are rare, declining or otherwise considered to be of conservation concern. PNHP records indicate that 329 tracked species have populations within pixels that have a relatively high modeled probability for Marcellus development. Nearly 40 percent (132) are considered to be globally rare or critically endangered or imperiled in Pennsylvania. Many are found in riparian areas, streams, and wetlands, while others are clustered in unusually biologically diverse areas such as the Youghiogheny Gorge. Some of these species may have only one, two or three populations left in the state. Two examples include the green salamander (*Aniedes aeneus)* with all known populations in relatively high probability Marcellus development pixels and snow trillium (*Trillium nivale*) with 73 percent of known populations in relatively high probability pixels. A well-managed screening system to identify the presence of these species and their preferred habitats will be critical to their survival as energy development expands across the state.

RECREATION

Pennsylvania has built one of the largest networks of public recreation lands in the eastern United States, but much of it could see Marcellus and other natural gas development in coming decades. Of the 4.5 million acres of state and federal lands in the state, we estimate as little as 500,000 acres are permanently protected from surface mineral development, including gas drilling. State and federal agencies do not own mineral rights under at least 2.2 million acres. Most other areas where the state does own mineral rights can be leased, such as the estimated 700,000 acres previously leased for gas development on state forest lands. Severe budget pressures will likely to tempt the legislature to lease additional lands in the future. Our projections excluded state Wild and Natural Areas, National Park lands, and Congressionally-designated Wilderness Areas but otherwise assumed that high probability Marcellus gas pixels on public lands could be developed. The low scenario projects 897 pad locations on State Forest and State Game Lands which expands to 1,438 well pads in the medium scenario and 2,096 pads in the high scenario. The focal area below illustrates what the overlap of future gas development and conservation lands could look like in the medium scenario for the southern Laurel Highlands. It projects 7 well pads in the portion of Forbes State Forest visible in the focal area above, 13 pads on State Game Lands 51, and 3 on State Game Lands 111.



Map showing projected Marcellus well pads under the medium scenario on public and private conservation lands in the Laurel Highlands.

Pennsylvania's state park system, recognized as one of the best in the nation, illustrates the challenge of protecting recreational values in areas of intensive Marcellus development. While the DCNR has a long standing policy of not extracting natural resources in state parks, it does not own the mineral rights under an estimated 80 percent of the system's 283,000 acres. Our projections indicate Marcellus well pads could be located in between 9 and 22 state parks.

AVOIDING FOREST IMPACTS IN THE LAUREL HIGHLANDS

The projected potential impacts of Marcellus gas energy development assume recent patterns of development will continue. Given the relatively large areas drained by Marcellus gas pads (depending on the lateral length and number of wells per pad), there is flexibility in how they are placed. This allows us potentially to optimize between energy production and conservation outcomes. To look at how conservation impacts could be minimized, we examined how projected Marcellus gas pads could be relocated to

Projected Well Pads on State Lands (Medium Scenario)	
DCNR State Forests	**1,002**
DCNR State Parks	**41**
State Game Lands	**436**
Total State Lands	**1,479**

avoid forest patches in the Southern Laurel Highlands in Fayette and Somerset counties. This area is important because it represents a unique ecological region with a large amount of state land as well as private farmland and forest land. The area is also facing great pressure to develop the Marcellus Gas resource. The focus area included approximately 350 square miles and included Chestnut Ridge on its western border and Laurel Ridge on its east. Within the area, there are two state parks (Ohiopyle State Park and Laurel Hill State Park), two State Game Lands (SGL 51, SGL 111), and state forest land (Forbes State Forest).

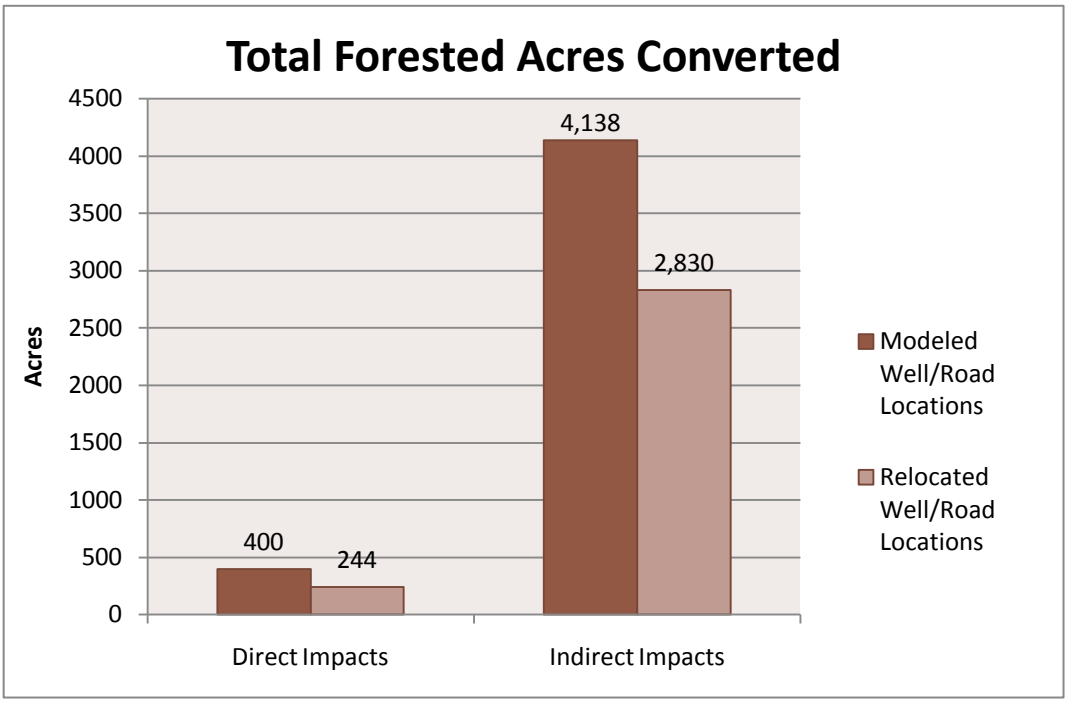
The Medium Scenario projected 127 well pads in the focus area. Fourteen well pads were projected in agricultural fields, 33 were in edge habitat (within 100 m of the forest edge), 11 fell within existing cleared areas (e.g. strip mines), and 69 were in forest. There were five pads on Ohiopyle State Park, and 13 within a mile of its boundary. Laurel Ridge State Park contained two pads. Forbes State Forest had seven modeled pads. State Game Lands 111 had 3 pads, and SGL 51 had 13. It was not clear if DCNR State Parks Bureau or the Game Commission control the sub-surface mineral rights beneath the 23 modeled pads. Given that 80 percent of mineral rights are severed on State Park and State Game Lands (and close to 100 percent in western parts of the state), we have assumed that drilling could happen at those projected locations.

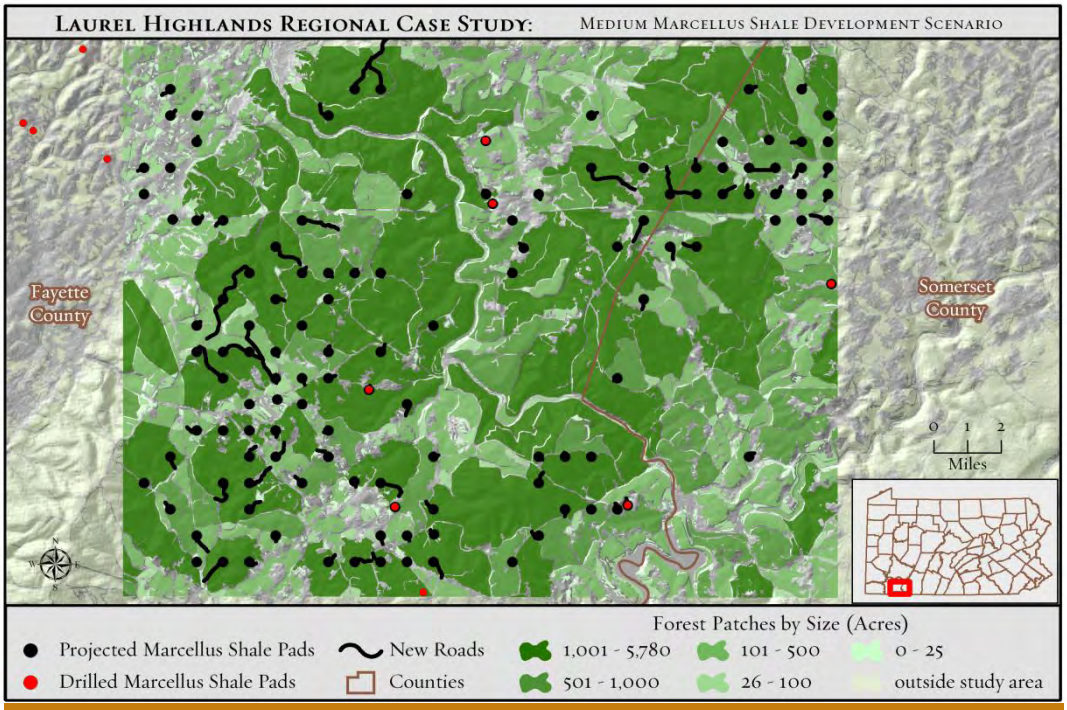
To assess additional impacts beyond the well pad itself, we placed a new and/or improved road from the projected pad to the nearest existing road (ESRI Roads Layer). We placed new roads along existing trails, paths and openings whenever detectable on aerial photo imagery (used Bing Maps and 2005-2006 PA Map imagery), avoiding wetlands, steep slopes, cliffs, rock outcrops, and buildings, and where possible, rivers, streams, and forest patches. The projected pads and roads required clearing 400 acres of forest.

Can a modest shift in the location of well pads reduce impacts to forest patches and conservation lands? To reduce the impacts to forest habitats, the wells were relocated to nearby existing anthropogenic openings, old fields, or agricultural fields. Attempts were made to maintain the 4,200 foot (1,260 m) distance between modeled wells. If nearby open areas did not exist, the locations of the well pads were moved toward the edges of forest patches to minimize impacts to forest interior habitats. A set of rules was developed and followed to minimize bias, including:

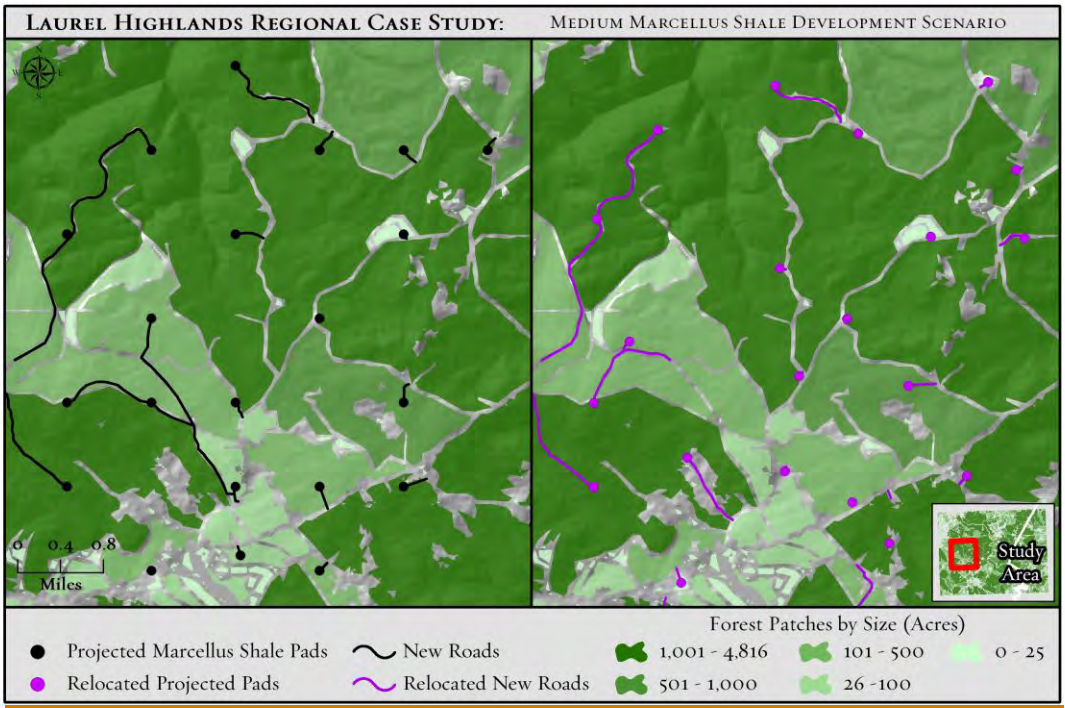
1. Modeled well pads were not relocated if they occurred in old fields or agricultural fields.
2. Modeled well pads that occurred in forest or edge habitat were moved but well pads were placed in the same general areas as the modeled well pad;
3. Attempts were made to avoid placing relocated well pads any closer that the minimum distance between pads, as specified by the medium scenario (1260 m)
4. Agriculture, cleared land (e.g., former strip mines), or otherwise opened land cover was favored over forest or edges for relocating well pads;
5. If the well pad could not be placed in an open area, forest edges were favored over deep interior forest;
6. Residential areas were avoided. Relocated well pads were placed at least 500 feet (150 m) from homes;
7. Wetlands, water, steep slopes, cliffs, rock outcrops, creeks and rivers, buildings and manicured lawns were avoided;
8. Relocated well pads were only placed in areas with similar to those that supported modeled pads.
9. Relocated well pads often were connected to roads using existing trails, paths and openings whenever detectable on aerial photo imagery (used Bing Maps and 2005-2006 PA Map imagery);
10. The same number of relocated well pads were placed on state lands and Western Pennsylvania Conservancy lands as they were in the modeled output;
11. When the modeled well pad occurred within a forest patch with no nearby alternative locations (due to proximity of other wells or environmental constraints), the projected well pad was not relocated.

The relocated wells and roads did not eliminate forest impacts in this heavily forested landscape, but there was a significant reduction. Total forest loss declined almost 40% while impacts to interior forest habitats adjacent to new clearings declined by a third.





Location of 127 projected Marcellus well pads and new roads in the study area in the southern Laurel Highlands.



Relocated well pads (on the right) reduced forest clearing and forest interior habitat impacts by 40 % and 33% respectively compared to the projected well pads (on the left).

Key Findings

Key findings from the Pennsylvania Energy Impacts Assessment for Marcellus Shale natural gas include:

- About 60,000 new Marcellus wells are projected by 2030 in Pennsylvania with a range of 6,000 to 15,000 well pads, depending on the number of wells per pad;

- Wells are likely to be developed in at least 30 counties, with the greatest number concentrated in 15 southwestern, north central, and northeastern counties;

- Nearly two thirds of well pads are projected to be in forest areas, with forest clearing projected to range between 38,000 and 90,000 acres depending on the number of number of well pads that are developed. An additional range of 91,000 to 220,000 acres of forest interior habitat impacts are projected due to new forest edges created by well pads and associated infrastructure (roads, water impoundments);

- On a statewide basis, the projected forest clearing from well pad development would affect less than one percent of the state's forests, but forest clearing and fragmentation could be much more pronounced in areas with intensive Marcellus development;

- Approximately one third of Pennsylvania's largest forest patches (>5,000 acres) are projected to have a range of between 1 and 17 well pads in the medium scenario;

- Impacts on forest interior breeding bird habitats vary with the range and population densities of the species. The widely-distributed scarlet tanager would see relatively modest impacts to its statewide population while black-throated blue warblers, with a Pennsylvania range that largely overlaps with Marcellus development area, could see more significant population impacts;

- Watersheds with healthy eastern brook trout populations substantially overlap with projected Marcellus development sites. The state's watersheds ranked as "intact" by the Eastern Brook Trout Joint Venture are concentrated in north central Pennsylvania, where most of these small watersheds are projected to have between two and three dozen well pads;

- Nearly a third of the species tracked by the Pennsylvania Natural Heritage Program are found in areas projected to have a high probability of Marcellus well development, with 132 considered to be globally rare or critically endangered or imperiled in Pennsylvania. Several of these species have all or most of their known populations in Pennsylvania in high probability Marcellus gas development areas.

- Marcellus gas development is projected to be extensive across Pennsylvania's 4.5 million acres of public lands, including State Parks, State Forests, and State Game Lands. Just over 10 percent of these lands are legally protected from surface development.

- Integration of conservation features into the planning and development of Marcellus gas well fields can significantly reduce impacts. For example, relocating projected wells to open areas or toward the edge of large forest patches in high probability gas development pixels in the southern Laurel Highlands reduces forest clearing by 40 percent and forest interior impacts by over a third.

Additional Information

- Geologic information on the Marcellus shale formation in Pennsylvania: http://www.dcnr.state.pa.us/topogeo/oilandgas/marcellus_shale.aspx

- Estimates of Marcellus shale formation gas reserves: http://geology.com/articles/marcellus-shale.shtml

- Baker-Hughes weekly oil and gas rig count http://gis.bakerhughesdirect.com/Reports/StandardReport.aspx

- Pennsylvania Department of Environmental Protection, Permit and Rig Activity Report: http://www.dep.state.pa.us/dep/deputate/minres/oilgas/RIG10.htm

- Copeland, H. E., K.E. Doherty, D.E. Naugle, A. Pocewicz, and J. M. Kiesecker. 2009. Mapping Oil and Gas Development Potential in the US Intermountain West and Estimating Impacts to Species: http://www.plosone.org/article/info%3Adoi%2F10.1371%2Fjournal.pone.0007400

- Overview of forest fragmentation impacts on forest interior nesting species: http://www.state.nj.us/dep/fgw/neomigr.htm

- Overview of Pennsylvania High Quality and Exceptional Value Streams: http://www.dcnr.state.pa.us/wlhabitat/aquatic/streamdist.aspx

- Pennsylvania Department of Environmental Protection, Chapter 93 Water Quality Standards, Exceptional Value and High Quality Streams: data downloaded from Pennsylvania Spatial Data Access: http://www.pasda.psu.edu

- Eastern Brook Trout Joint Venture intact brook trout watersheds: http://128.118.47.58/EBTJV/ebtjv2.html

- Overview of Carnegie Museum of Natural History, Powdermill Nature Reserve, and the Pennsylvania Game Commission's 2nd Pennsylvania Breeding Bird Atlas Project: http://www.carnegiemnh.org/powdermill/atlas/2pbba.html

- Pennsylvania Natural Heritage Program, including lists of globally rare and state endangered and imperiled species: http://www.naturalheritage.state.pa.us/

- U.S. Department of Agriculture, Natural Resources Conservation Service, National Agriculture Imagery Program: http://datagateway.nrcs.usda.gov/GDGOrder.aspx

- DigitalGlobe, GlobeXplorer, ImageConnect Version 3.1: http://www.digitalglobe.com

Wind

Wind has become one of the country's fastest growing sources of renewable energy. Pennsylvania is a leader in the industry as host to several wind company manufacturing plants and corporate headquarters. Wind energy development has been spurred by its potential to reduce carbon emissions, promote new manufacturing jobs, and increase energy independence. Technological advances have expanded the size and efficiency of wind turbines during the past decade. This, together with state and federal incentive programs, has facilitated wind development in Pennsylvania, which otherwise ranks relatively low among states for its potential wind generation capacity. The eight turbines installed next to the Pennsylvania Turnpike in Somerset County a decade ago have grown to nearly 500 turbines, with more permitted for construction (AWEA, 2010). Topography is a key factor in average wind speeds across Pennsylvania, so nearly all turbines have been built on mountain ridgelines or on top of high elevation plateaus.

Wind energy has become the most symbolic icon of the shift toward a low carbon economy. With no air emissions or water consumption, it is one of the cleanest renewable energy types. Communities across the state benefit economically as rural landowners lease their properties, skilled jobs are created to manufacture turbines, and workers are hired to install and maintain turbines. Wind development has faced controversy in some areas from neighboring landowners and those worried about impacts to migrating birds and bats. The wind industry, government agencies, and independent researchers have invested considerable effort in trying to better understand impacts on birds and bats. For example, 26 wind development companies have signed a cooperative agreement with the Pennsylvania Game Commission to conduct bird, bat and animal surveys using specified protocols in proposed development areas. Among other findings have been the discovery of the Pennsylvania's second largest Indiana bat maternal colony and a variety of previously undocumented foraging and roosting locations for the state's two rarest bats (Indiana and eastern small-footed). Less understood are the potential habitat impacts of wind development in the northeastern United States. This assessment, therefore, focuses on impacts to forest and stream habitats and selected species of conservation concern that may be vulnerable to development of ridgetop habitats.

What is Wind Energy?

Wind mills have powered grain processing and water pumping in agriculture around the world – most famously in the Netherlands – for centuries. The first modern wind facilities to generate electricity were built in California in the early 1980s. Rated at less than 0.5 MW capacity per turbine, the towers were only 50 feet tall. These facilities were poorly designed and generated considerable controversy because they caused significant mortalities to migrating hawks and eagles. Wind energy development did not expand appreciably until the late 1990s when newer turbine designs and federal energy incentives stimulated the development of new facilities. These turbines were rated at 1.0 or 1.5 MW capacity and reached about 200 feet high at the tip of their rotor. Since the power produced by a wind turbine is proportional to the cube of the blade size and how high in the air it is; turbine size, height and power ratings have expanded steadily. The largest turbines installed in Pennsylvania are now rated at

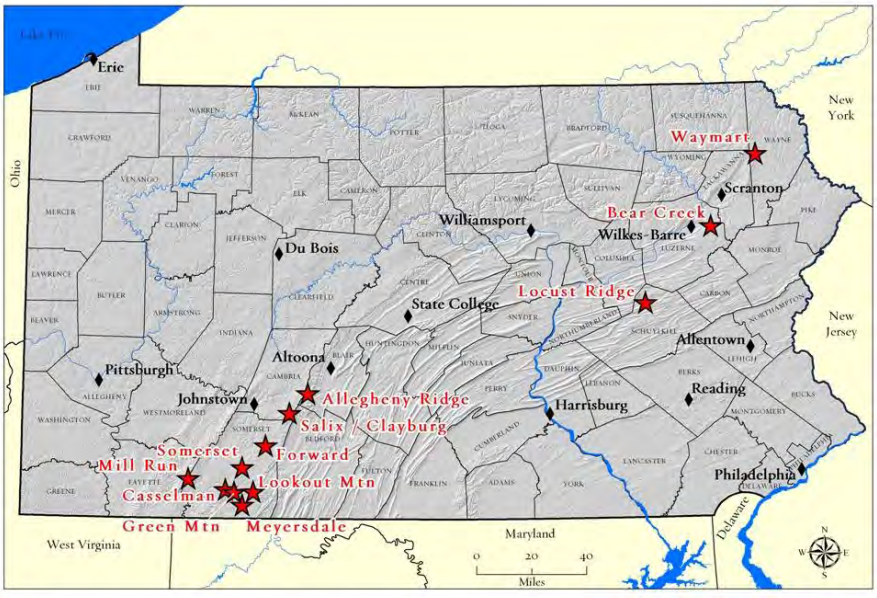
2.5 MW (the average was 1.8 MW in 2009) and reach over 400 feet to the tip of the rotor at the apex of its rotation.

Location is everything for wind development in the northeastern United States. Unlike the vast windswept plains in the Midwest and the intermountain West, high wind speeds in the Northeast are primarily confined to mountain ridgetops, plateau escarpments, and the Atlantic and Great Lake shorelines. Areas that have a wind power class rating of 3 or more (300 watts per m^2) are potentially feasible for wind power development. Wind companies will lease areas that seem to have the most favorable characteristics including wind class, flat pad sites, proximity to transmission lines, and proximity to existing highways. Before development, a wind development company will typically place an anemometer tower on potential development sites to improve knowledge about wind power at the site during a year or longer monitoring period. The turbines are mounted on pads at least 800 feet apart with an access road between towers. The average size of wind facilities has been growing steadily since the first eight were established in 2000. The two largest facilities are now between 75 and 100 turbines.

Several steps have been taken to address potential conflicts between wind development and wildlife in Pennsylvania. The Pennsylvania Game Commission (PGC) has a voluntary agreement in place with most wind companies active in the state to screen proposed facilities for possible impacts to birds and bats and migratory pathways. Participating wind companies carry out pre-construction monitoring for birds and bats. If possible conflicts are identified, PGC works with wind companies to avoid or minimize impacts and to continue monitoring post construction in some cases. Second, the Pennsylvania Wind and Wildlife Collaborative (PWWC) was established in 2005 with a state goal to develop a set of "Pennsylvania-specific principles, policies and best management practices, guidelines and tools to assess risks to habitat and wildlife, and to mitigate for the impact of that development." Several studies on wildlife and habitat issues have been commissioned, though guidelines and Best Management Practices (BMPs) have not been released.

Current and Projected Wind Energy Development

We documented the spatial foot print of 319 wind turbines at 12 wind facilities across the state by comparing aerial photos taken before and after development. Turbine pads, roads, and other new clearings were digitized for all 12 facilities visible in 2008 images from the

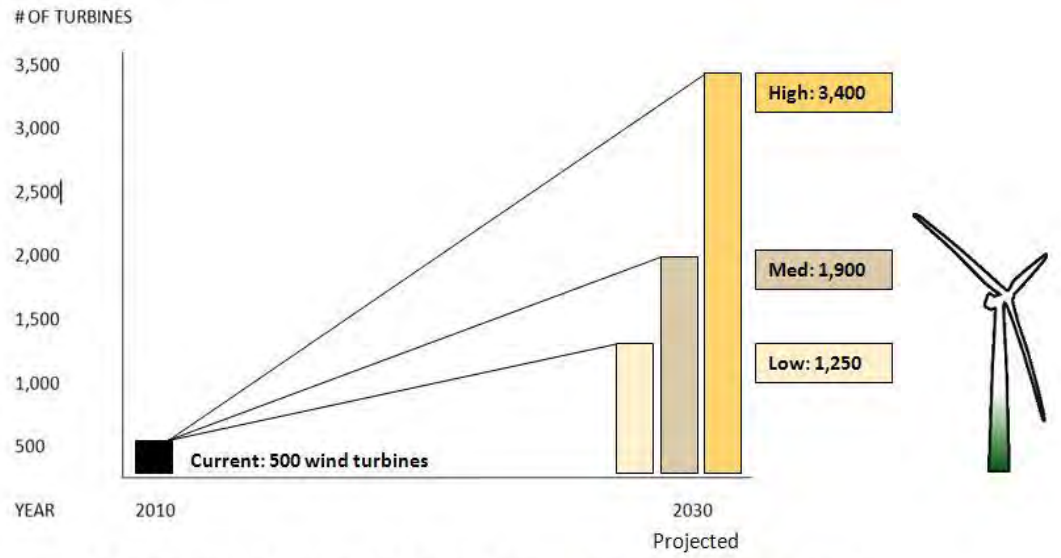


Map showing 12 wind facilities included in the spatial footprint analysis.

Average Spatial Disturbance for Wind Energy Development in Forested Context (acres)		
Forest cleared for wind turbine	1.4	1.9
Forest cleared for associated infrastructure (roads, other cleared areas)	0.5	
Indirect forest impact from new edges	13.4	
TOTAL DIRECT AND INDIRECT IMPACTS	15.3	

National Agriculture Imagery Program. The ground excavated for turbines, roads, and associated infrastructure (e.g., clearings for constructions staging areas or electrical sub-stations) is the most obvious spatial impact. For each turbine site, turbine pads, new roads, staging areas, and sub-stations were digitized and measured. Turbine pads occupy 1.4 acres on average, while the associated infrastructure (roads, staging areas, and substations) takes up an additional half acre, for a total of 1.9 acres of spatial impact per wind turbine.

As with Marcellus gas development, adjacent lands can also be impacted even if they are not directly cleared (See p. 11 for a description of forest edge impacts on forest "interior" species). To assess the potential interior forest habitat impact, we created a 330 foot buffer into forest patches from new edges created by wind turbine and associated infrastructure development. For turbine sites developed in forest areas (about 80% of the 319 turbines), an average area of 13.4 acres of interior forest habitat was lost in addition to the 1.9 acres of directly cleared forest.



Key drivers: Alternative Energy Portfolio Standard (AEPS) and projected contribution of wind to meeting that standard.

We project between 1,250 and 3,400 total wind turbines will be erected in Pennsylvania by 2030.

The number of wind turbines built in Pennsylvania will certainly expand during the next two decades. Various factors will drive exactly how many turbines are ultimately built including electricity prices, state and federal incentives, technological improvements, energy and climate policy, regulatory changes, and social preferences. Our projections assume economic, policy, and social conditions will remain favorable enough to promote steady expansion of wind development in the state since we cannot reasonably forecast energy prices, technological developments, and policy conditions. The key driver in our low scenario is that companies will use wind energy to meet 70 percent of the current Alternative Energy Portfolio Standard (AEPS) Tier 1 standard (8 percent of electric generation). This projection indicates an additional 750 turbines (2 MW average) will be added to the 500 turbines currently operating. The key driver in our medium scenario is that utilities will use wind energy to meet 70 percent of an expanded AEPS 15% Tier 1 standard, as proposed in recent draft legislation. That scenario would add 1,400 new turbines to those already built. The high scenario used in this assessment is based on the 20% wind power electric generation scenario used by the National Renewable Energy Laboratory in the Eastern Wind Integration Study (EWITS). This scenario would require 2,900 additional turbines.

Where are those new turbines in each scenario more and less likely to go? To start, we created a probability surface by looking at a range of variables that might be relevant to a company's decision to develop a wind facility with wind turbines that have already been built. We used the maximum entropy modeling approach used to develop the Marcellus gas probability surface (see p. 13) and built the model using 580 existing and permitted wind turbines. Variables that potentially drive wind energy development were chosen based on data availability and included wind power (W/m^2), distance to transmission lines, percent slope, distance to roads, and land cover. An additional 193 existing and permitted wind turbines were used to test the validity of the model's probability surface and the model was found to be 95.8% accurate in predicting existing and permitted turbines from randomly sampled undeveloped areas. The resulting probability map indicates many long, narrow high probability sites along ridge tops, and several wider areas on high plateaus and along the Lake Erie coastline.

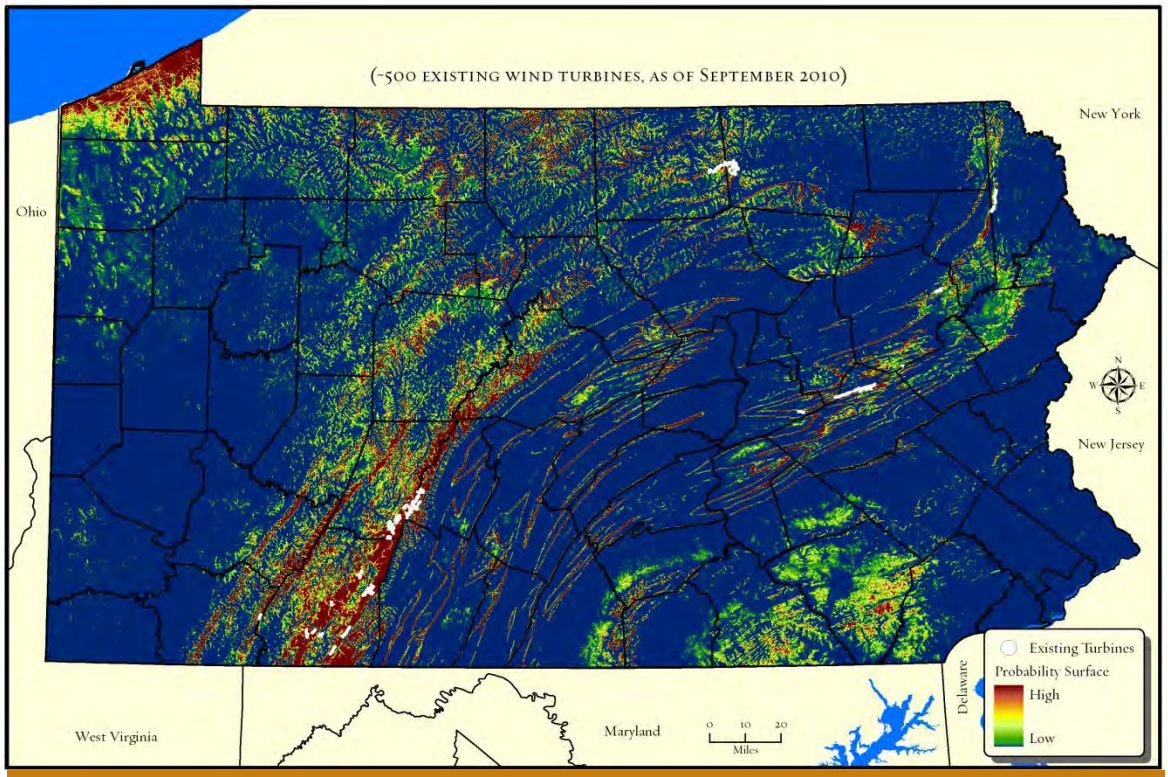
To determine where wind development is more likely, we searched for the highest probability areas where wind turbines in each scenario might be located. The probability surface was re-sampled from 30-meter to 60-meter resolution (0.89 acres) to represent the approximate geographic footprint of wind turbines based on aerial photo assessment. We selected the highest probability pixel, buffered that pixel by a minimum separation distance of 800 feet (240 meters – the average minimum distance between existing turbines), and then selected the next highest probability pixel, and so on. Pixels were selected until the threshold for each scenario was reached (low – 700 turbines; medium – 1,200 turbines; high – 2,700 turbines). The selected pixels were then converted into points for map display purposes.

The resulting projected turbine locations occurred in strings, groups, or scattered single turbines, mostly in southwest, north central and northeastern parts of Pennsylvania. Wind turbines, however, are almost always located in clusters rather than widely separated locations for individual turbines. In order to represent viable wind farms, we selected clusters of pixels with high probability to represent viable wind facilities, based on the following:

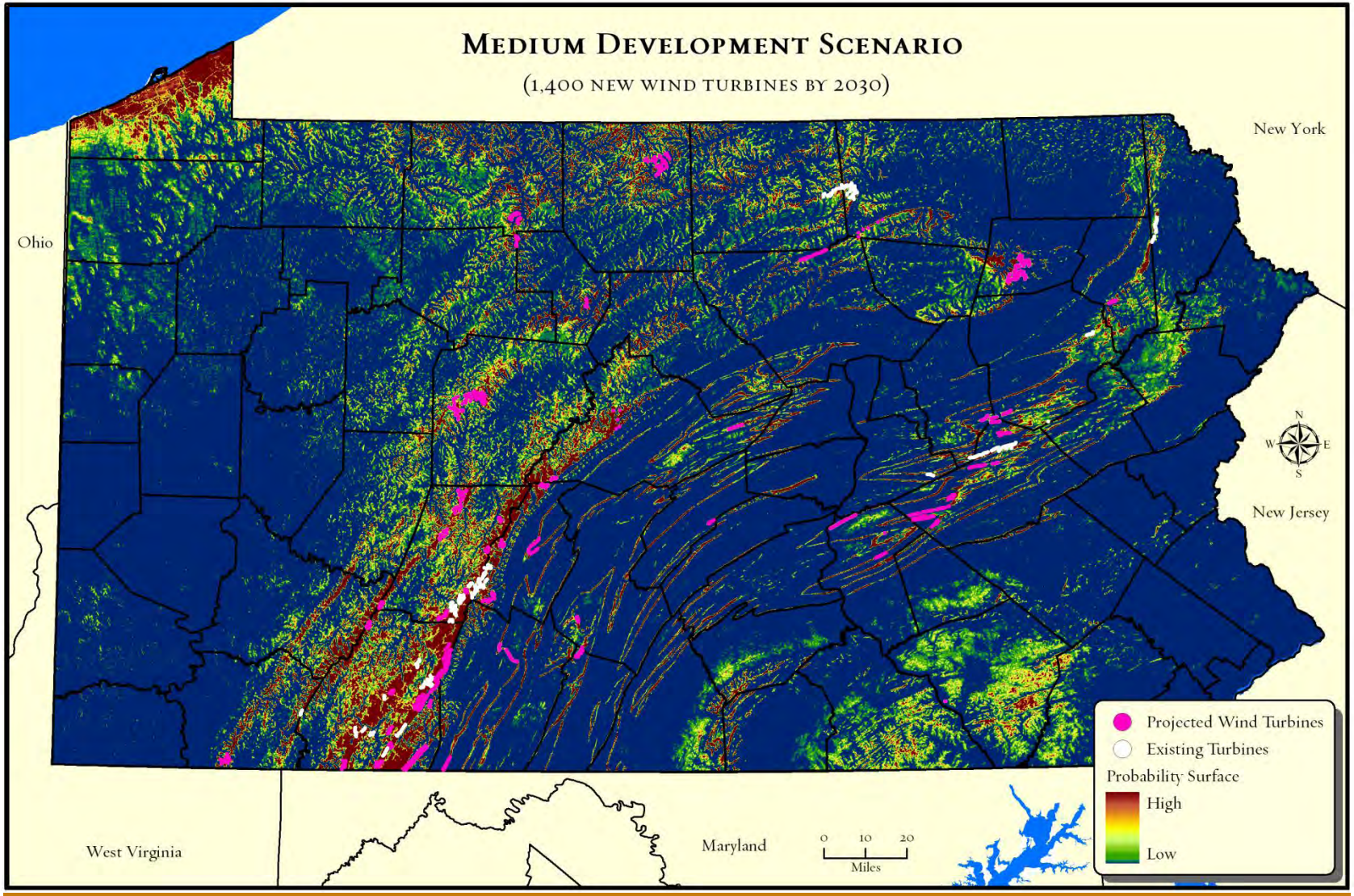
- Excluded areas approximately 300 meters (1,000 ft) from existing homes (as visible in aerial imagery)
- Excluded buffers of regional airports by 6,096 m (20,000 ft) and local airports by 3,048 m (10,000 ft)
- Excluded buffers of existing turbines (buffer = 960 m or 4 times the minimum turbine separation distance of 240 m)
- Excluded Pennsylvania State Parks, Pennsylvania State Forests, and Pennsylvania State Game Lands
- Excluded setbacks of 152 m (500 ft) from the boundaries of state and federal lands

- Required a minimum of 6 projected turbines grouped together to be considered a potentially viable site
- Selected already proposed wind turbines (based on permit data from the Federal Aviation Administration)

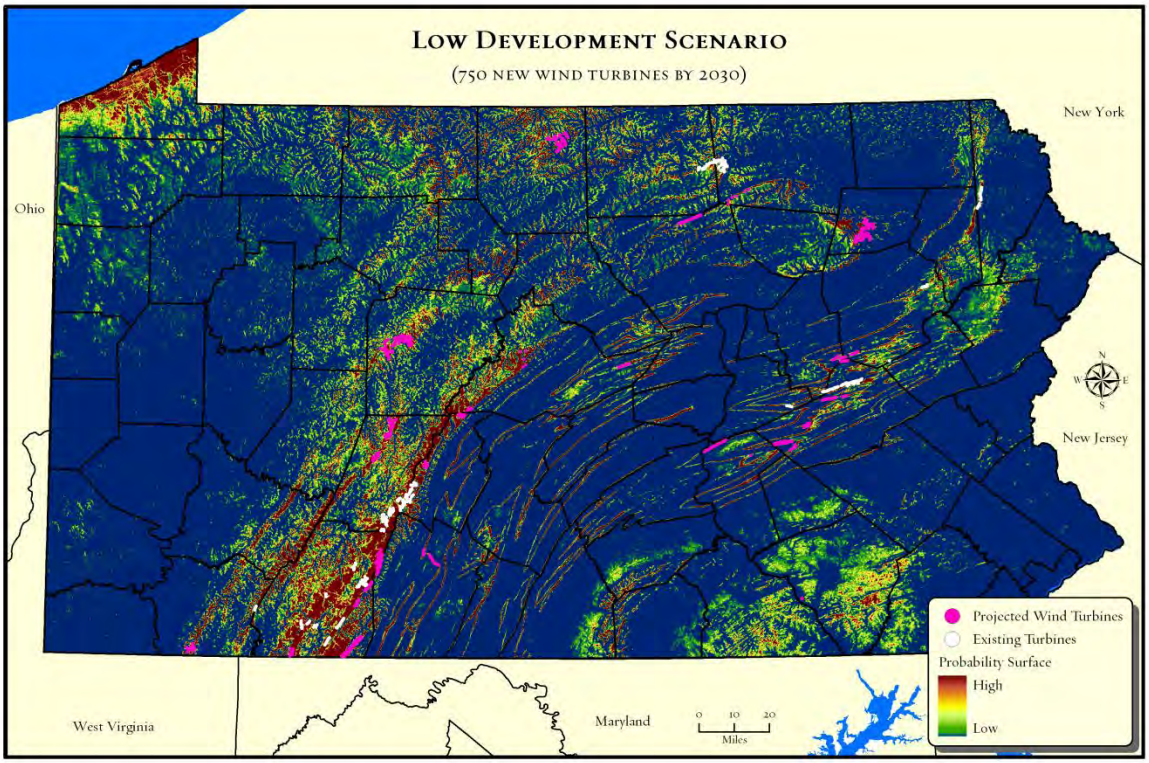
Potential wind facilities were manually selected by identifying groupings of projected wind turbines. Scenarios are cumulative, so the medium scenario includes turbines in both the low and medium scenarios, whereas the high scenario includes all projected turbines.



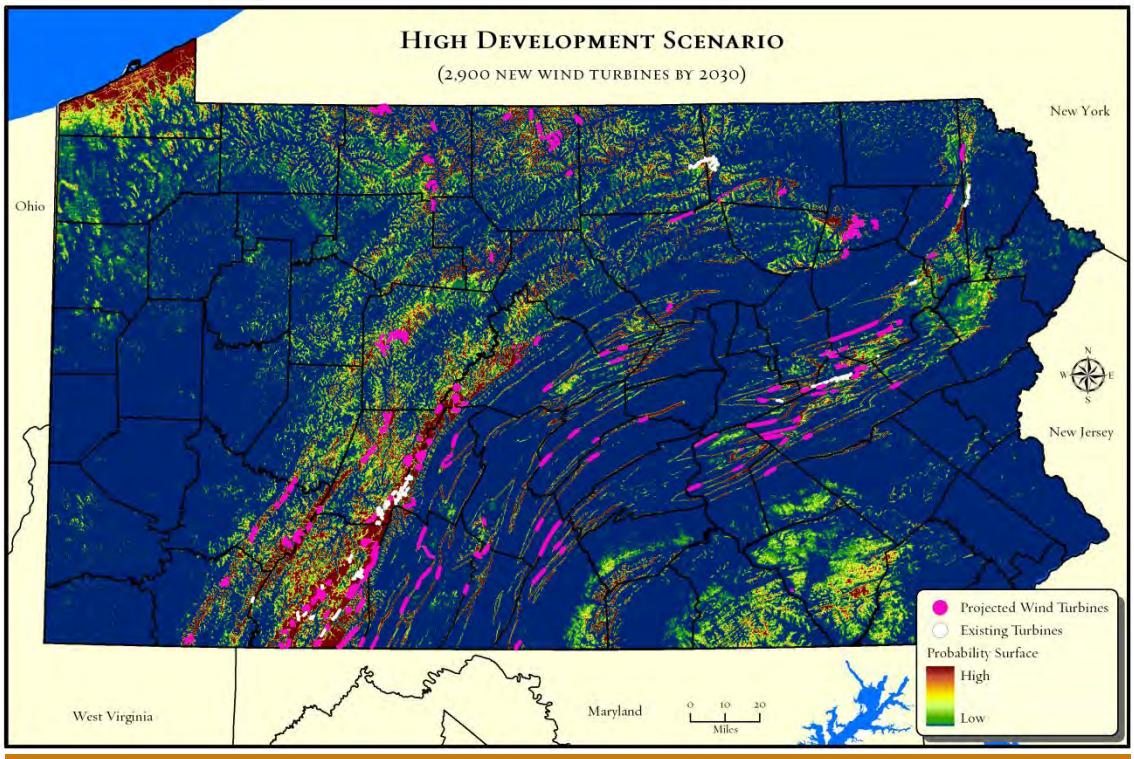
Map showing existing wind turbines with the probability that a given area will be developed indicated by color (dark red is high probability; dark blue is low).



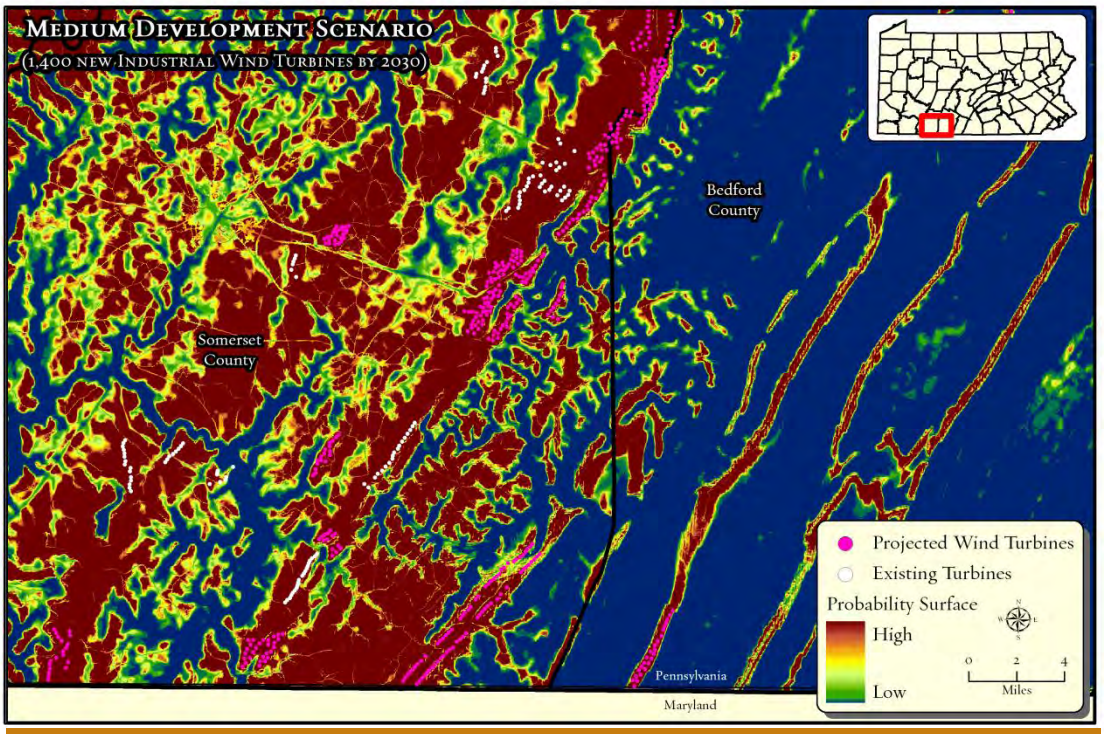
Map showing 1,400 new wind turbines projected by 2030 under the medium development scenario.



Map showing 750 new wind turbines projected by 2030 under the low development scenario.



Map showing 2,900 new wind turbines projected by 2030 under the high development scenario.



Map showing medium wind development scenario within Somerset and Bradford counties.

These geographic projections of future wind energy development are spatial representations of possible scenarios. They are not predictions. We faced several constraints in developing the geographic scenarios:

- We do not have the detailed wind power data that wind companies have developed through anemometer tower monitoring.
- We do not have the detailed location of wind energy leases.

Still, we believe the overall geographic patterns in the projected wind development locations are relatively robust for several reasons. We used over 500 existing or permitted wind turbines to build the model and nearly 200 additional existing and permitted wind turbine sites were used to validate the model. This is typically a sufficient sample size for building predictive models. They are also consistent with Black and Veatch (2010) projected locations for wind facilities under a 15% renewable energy portfolio standard.

Conservation Impacts of Wind Energy Development

What is the overlap of the areas with the highest probability of future wind energy development and those areas known to have high conservation values? To answer this question, we intersected the projected wind energy facilities with high conservation value areas. We looked at several examples from four categories of conservation value, including:

- Forest habitats
- Freshwater habitats

- Species of conservation concern
- Outdoor recreation

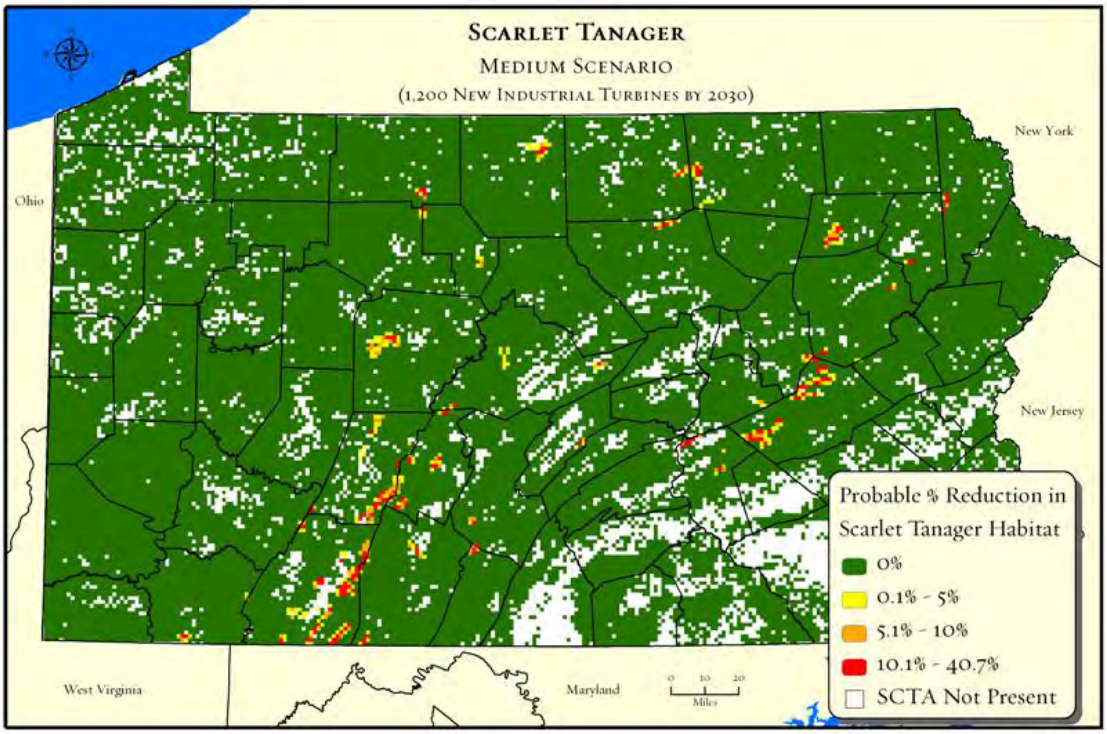
Areas of overlap between likely future wind development areas and priority conservation areas in Pennsylvania are substantially less than the conservation area overlap with likely future Marcellus development areas, largely because the projected foot print will be much smaller.

Forests

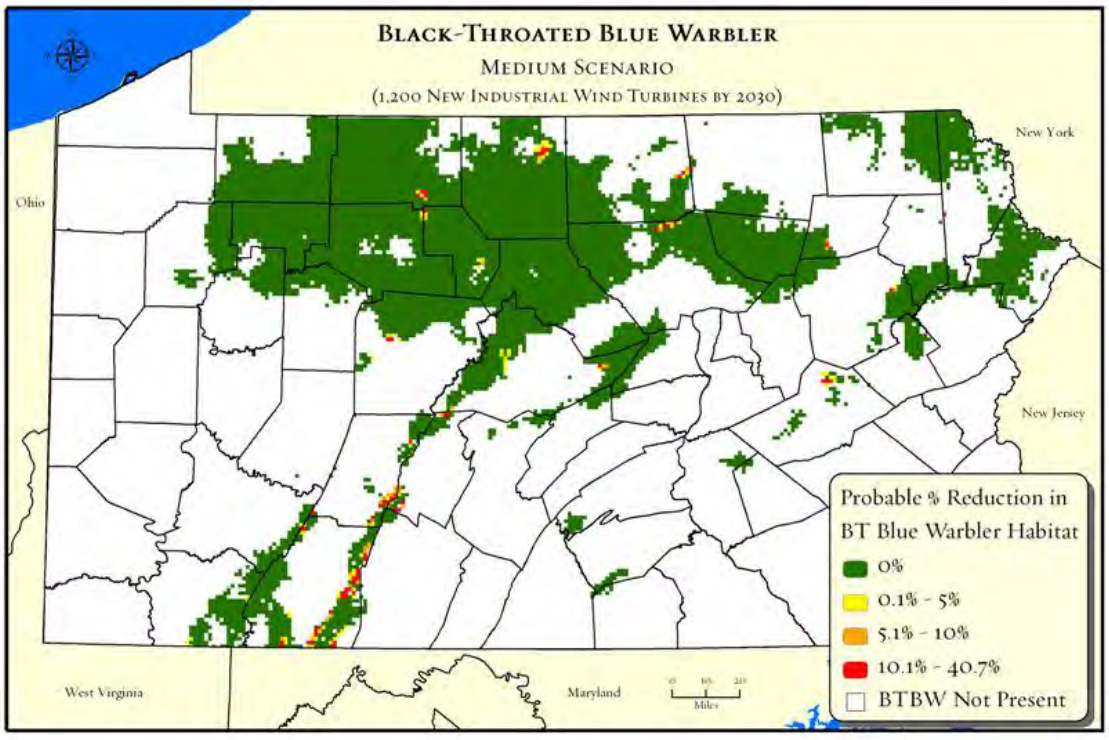
A large majority of projected wind turbines are found in forest patches, about 80 percent for each of the scenarios. The low scenario would see 600 new wind turbines in forest areas. With a cleared forest average of 1.9 acres per turbine (including roads and other infrastructure), the total forest loss would be a modest 1,900 acres. Indirect impacts to adjacent forest interior habitats would total an additional 13,400 acres. Forest impacts from the medium scenario (1,520 projected turbines in forest locations) would be 2,900 cleared forest acres and an additional 20,400 acres of adjacent forest interior habitat impacts. For the high scenario (2,720 turbines in forest areas) 5,200 acres would be cleared and an additional 36,500 acres of forest interior habitats would be affected by new adjacent clearings. On a statewide basis, the projected forest losses and accompanying interior forest habitat impacts will be minor given the Pennsylvania's 16 million acres of forest. Locally, these impacts could be significant for individual large forest patches where wind development takes place.

All forests have conservation value, but large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, such as northern goshawk, than small patches. They are also more resistant to the spread of invasive species, can better withstand damage from wind and ice storms, and provide more ecosystem services – from carbon sequestration to water filtration – than small patches. The Nature Conservancy and the Western Pennsylvania Conservancy's Forest Conservation Analysis mapped nearly 25,000 forest patches in the state greater than 100 acres. Patches at least 1,000 acres in size are about a tenth of the total (2,700). The medium projected wind development scenarios indicate 73 patches (3%) greater than 1,000 acres in size are projected to have at least one wind turbine and associated infrastructure. Patches at least 5,000 acres in size are relatively rare (only 316 patches). The medium wind scenario indicates about 21 (7%) of these patches could be affected by future wind turbine development. Most affected large patches have multiple projected wind turbines (as many as 36). Typically, a large patch is split by wind development into two or three smaller patches due the linear pattern of development. Projected gas well pads, by contrast, are more likely to fragment a large patch into multiple smaller patches.

Forest interior bird species could be affected by the clearing of forest and adjacent edge effects that wind turbine facilities create in a forest context. We used data from the 2nd Breeding Bird Atlas Project (see p. 20) to assess the potential impact on forest interior species. The resulting maps show the estimated reduction in habitat for that species in each high wind development gas probability pixel (including both cleared forest and adjacent edge effects). Scarlet Tanagers are perhaps the most widespread forest interior nesting bird in the state. Since they are so widespread, the vast majority of their range in the state is outside of the most likely wind development areas. Scarlet Tanager populations could decline by an insignificant amount due to habitat losses projected in the medium scenario. Black-throated blue warblers are more narrowly distributed in Pennsylvania favoring mature northern hardwood and coniferous forests with a thick understory, frequently in mountain terrain. Likewise, population declines would also be extremely small for Black-throated blue warblers under the medium scenario.



Map showing estimated percent loss of habitat for Scarlet Tanagers under the medium wind scenario.

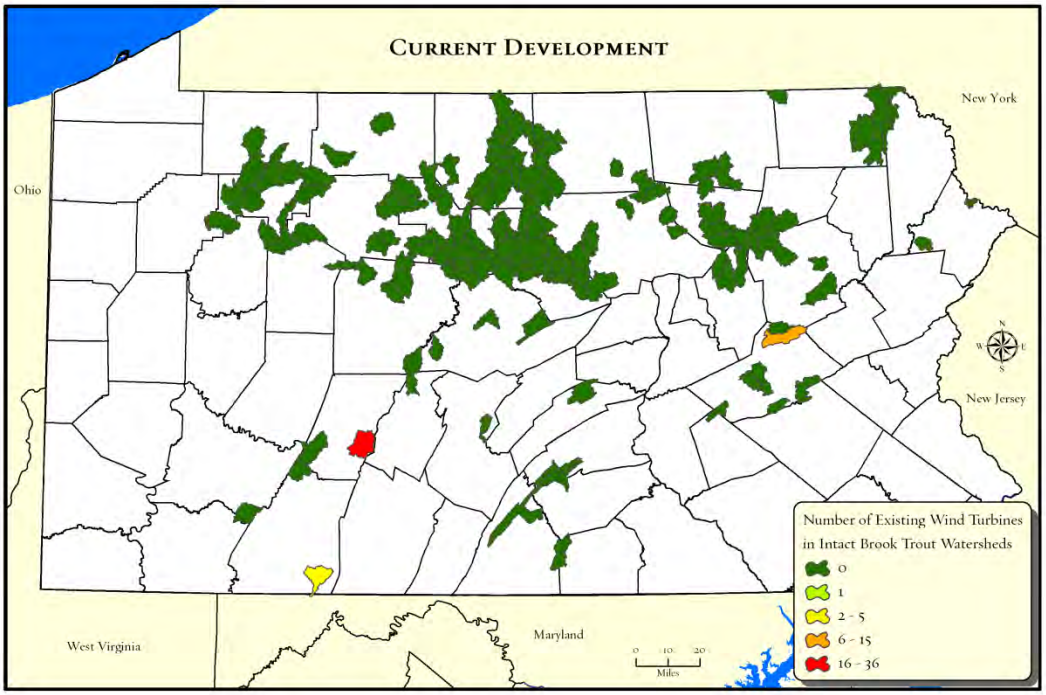


Map showing estimated percent loss of habitat for Black-Throated Blue Warblers under the medium wind scenario.

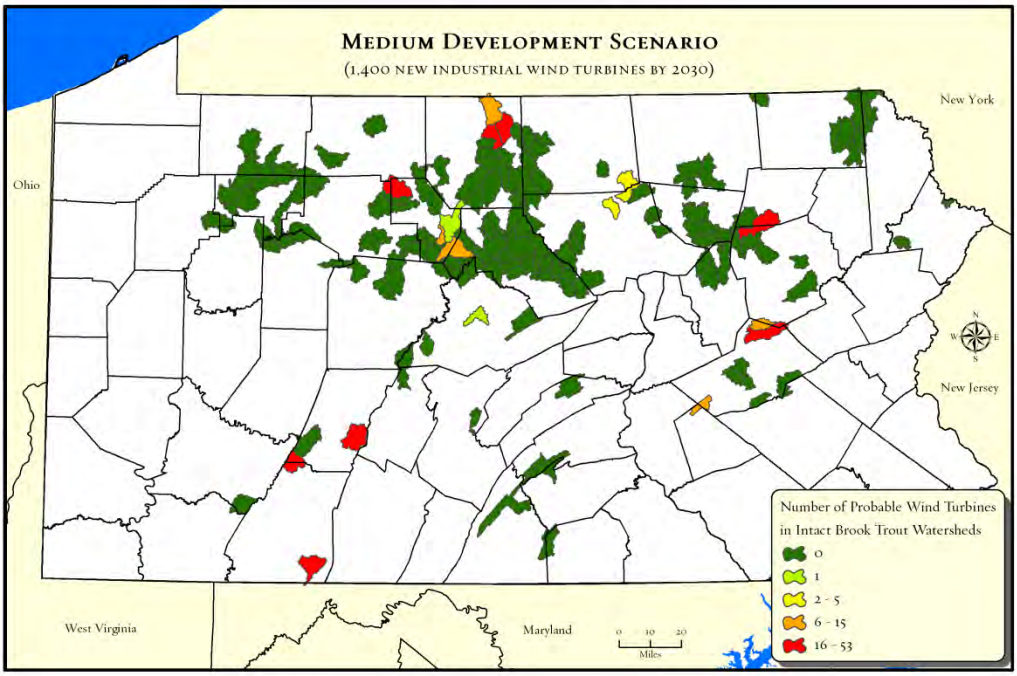
Freshwater

Wind energy and freshwater habitats are not often thought of in the same context since most wind facilities are generally in high elevation areas away from rivers and streams. The exceptions are small headwater streams, some of which may be classified as Exceptional Value watersheds. Our medium scenario projection indicates that 9 percent of future turbine development could be located within ½ mile of an Exceptional Value stream.

Native brook trout are one of the most sensitive species in Pennsylvania watersheds. Brook trout favor cold, highly-oxygenated water and are unusually sensitive to warmer temperatures, sediments, and contaminants. Once widely distributed across Pennsylvania, healthy populations have retreated to a shrinking number of small watersheds. The potential impact on intact brook trout watersheds, however, does increase significantly between the low to high scenarios. Wind turbines have been built in just five of the intact brook trout watersheds identified by the Eastern Brook Trout Joint Venture. That number would expand to 13 in the low scenario, 19 in the medium scenario, and 28 in the high scenario. The presence of wind turbines may pose a limited risk in many of these watersheds, principally from soil disturbance near headwater streams.



Map showing current number of wind turbines in intact and predicted intact brook trout watersheds.



Map showing projected number of wind turbines in intact brook trout watersheds (by 2030) under medium scenario.

Poorly designed or maintained sedimentation measures, especially on road cuts and stream crossings, is the principal risk to these sensitive populations.

Rare Species

Of the approximately 100,000 species believed to occur in Pennsylvania, just over 1 percent is tracked by The Pennsylvania Natural Heritage Program (PNHP). These species are rare, declining or otherwise considered to be of conservation concern. PNHP records indicate that 77 tracked species have populations within pixels that have a relatively high modeled probability for wind development. Most of these species are commonly found in rocky outcrops and scrub oak/pitch pine barrens habitats on ridgetops across the state. Only a handful of species, however, have more than a few occurrences overlapping with the relatively high probability wind development pixels. For example, the eastern timber rattlesnake (*Crotalus horridus*) and Allegheny woodrat (*Neotoma magister*) are strongly associated with rocky outcrops and talus slopes along or near ridgetops. Six percent of the rattlesnake's known rattlesnake breeding/denning sites and three percent of Allegheny woodrat den sites are located in relatively high wind probability pixels. The den sites are very small sites and do not include foraging areas. The Pennsylvania Natural Heritage Program has developed core habitat polygons for each Allegheny woodrat occurrence. Much larger than the den locations, these polygons indicate a much broader overlap – 43 percent – with relatively high probability pixels for wind development. The Northern long-eared Myotis bat (*Myotis septentrionalis*) has about eight percent of its known winter hibernation and summer roosting areas overlapping with relatively high probability wind development pixels. Ridgetop barrens communities in northeastern Pennsylvania have some of the state's largest concentrations of rare terrestrial species. The Nature Conservancy has mapped these communities, and some of these habitats overlap with high wind areas. In general, there appears to be relatively little overlap between tracked species occurrences in Pennsylvania and likely wind

development sites. For a handful of species, there is enough overlap to indicate the importance of surveys early in the project planning stage to identify the presence of rare species and their core habitats.

We have not addressed the potential impact of these scenarios on bird migration patterns and bat foraging populations. For more information on wind development impacts on bird and bat species, please see links to the Pennsylvania Game Commission, U.S. Fish and Wildlife Service, American Wind and Wildlife Institute, and Bat Conservation International.

Recreation

Wind development has not occurred on any state or federal lands in Pennsylvania to date. Since our projections assume there will not be a significant change in state land leasing policies for wind development, we have not projected new wind turbines in State Parks, State Forests or State Game Lands. Our projections, however, do indicate that wind turbines will be located in close proximity (sometimes as close as 500 feet) to many state lands. They are likely to be highly visible in some heavily visited areas, such as Blue Knob State Park in Bedford County, where natural landscape vistas are a prime attraction.

Key Findings

Key findings from the Pennsylvania Energy Impacts Assessment include:

- Projections of between 750 and 2,900 new wind turbines developed on ridgetops and high plateaus by 2030, depending on the size of the Pennsylvania Alternative Energy Portfolio standard. There are currently an estimated 500 wind turbines built in the state.

- Wind turbine facilities are likely to be developed in half of the state's counties, especially along the Allegheny front in western Pennsylvania and on high Central Appalachian ridges in central and northeastern parts of the state;

- Nearly eighty percent of turbine locations are projected to be in forest areas, with forest clearing projected to range between 1,900 and 5,200 acres depending on the number of turbines developed. An additional range of 13,400 to 36,500 acres of forest interior habitat impacts are projected due to new edges created by turbine pads and roads;

- On a statewide basis, the projected forest clearing from turbine development is relatively minor, though some of the state's largest forest patches (>5,000 acres) could be fragmented into smaller patches by projected wind turbine development;

- Impacts on forest interior breeding bird habitats appear to be limited, largely because the overall footprint for the projected wind turbine facilities is small in comparison to the typical breeding range of these species in Pennsylvania. The study did not assess impacts to migratory pathways for birds or foraging bats.

- Relatively few watersheds ranked as "intact" by the Eastern Brook Trout Joint Venture are affected by projected wind turbine development. Several intact watersheds, however, could see several dozen wind turbines. In a number of cases, these small watersheds are projected to see significant Marcellus gas development as well. Given the cumulative impact of these activities, rigorously designed and monitored sediment control measures will be needed to protect sensitive brook trout populations.

- A relatively small handful of rare species occurrences tracked by the Pennsylvania Natural Heritage Program are found in areas with high probability for wind development. These species tend to be associated with rocky outcrops and barrens communities typically found on ridge tops, including the Allegheny wood rat, the eastern timber rattlesnake, and the northern long-eared Myotis bat.

- Wind development is not projected to occur on Pennsylvania's public lands. Existing and projected wind turbines, however, will be close to some of Pennsylvania's most heavily visited outdoor recreation areas where scenic natural vistas are a major attraction.

Additional Information

- American Wind Energy Association (2010). U.S. Wind Projects Database. http://www.awea.org/la_usprojects.cfm
- Black and Veatch (2010). Assessment of a 15 Percent Pennsylvania Alternative Energy Portfolio Standard. Report prepared for the Community Foundation for the Alleghenies, Johnstown, PA. http://www.cfalleghenies.org/pdf/aepss.pdf
- Federal Aviation Administration (FAA) permits for wind turbines: https://oeaaa.faa.gov/oeaaa/external/public/publicAction.jsp?action=showCaseDownloadForm
- Federal Aviation Administration (FAA), Obstruction Evaluation / Airport Airspace Analysis (OE/AAA): https://oeaaa.faa.gov/oeaaa/external/public/publicAction.jsp?action=showCaseDownloadForm
- Pennsylvania Wind Farms and Wildlife Collaborative: http://www.dcnr.state.pa.us/wind/index.aspx
- PA Game Commission (2007) Wind Energy Voluntary Cooperative Agreement and First Annual Report for the Wind Energy Voluntary Cooperative Agreement: http://www.portal.state.pa.us/portal/server.pt?open=514&objID=613068&mode=2
- Pennsylvania Department of Environmental Protection, Chapter 93 Water Quality Standards, Exceptional Value and High Quality Streams: data downloaded from Pennsylvania Spatial Data Access: (www.pasda.psu.edu)
- U.S. Department of Energy TrueWind 80 Meter Wind Resource Maps: http://www.windpoweringamerica.gov/wind_maps.asp
- U.S. Fish and Wildlife Service Wind Turbine Advisory Committee: http://www.fws.gov/habitatconservation/windpower/wind_turbine_advisory_committee.html
- U.S. Environmental Protection Agency summary of forest fragmentation effects: http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewInd&lv=list.listByAlpha&r=219658&subtop=210
- Overview of forest fragmentation impacts on forest interior nesting species: http://www.state.nj.us/dep/fgw/neomigr.htm
- Overview of Pennsylvania High Quality and Exceptional Value Streams: http://www.dcnr.state.pa.us/wlhabitat/aquatic/streamdist.aspx
- Eastern Brook Trout Joint Venture intact brook trout watersheds: http://128.118.47.58/EBTJV/ebtjv2.html

- Overview of Carnegie Museum of Natural History, Powdermill Nature Reserve, and the Pennsylvania Game Commission's 2nd Pennsylvania Breeding Bird Atlas Project: http://www.carnegiemnh.org/powdermill/atlas/2pbba.html

- Pennsylvania Natural Heritage Program, including lists of globally rare and state endangered and imperiled species: http://www.naturalheritage.state.pa.us/

- U.S. Department of Agriculture, Natural Resources Conservation Service, National Agriculture Imagery Program: http://datagateway.nrcs.usda.gov/GDGOrder.aspx

pennsylvania
DEPARTMENT OF CONSERVATION
AND NATURAL RESOURCES

Impacts of Leasing Additional State Forest for Natural Gas Development

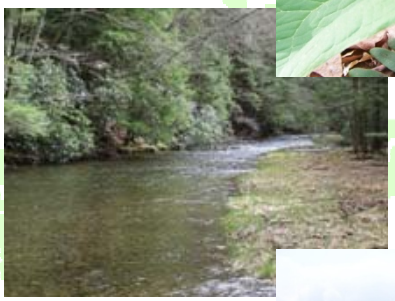
pennsylvania
DEPARTMENT OF CONSERVATION
AND NATURAL RESOURCES

DCNR is entrusted to balance the uses and values of our state forests while protecting the integrity and health of the whole system.

There are proposals and public debate about the merits of a moratorium on natural gas drilling on state forest.

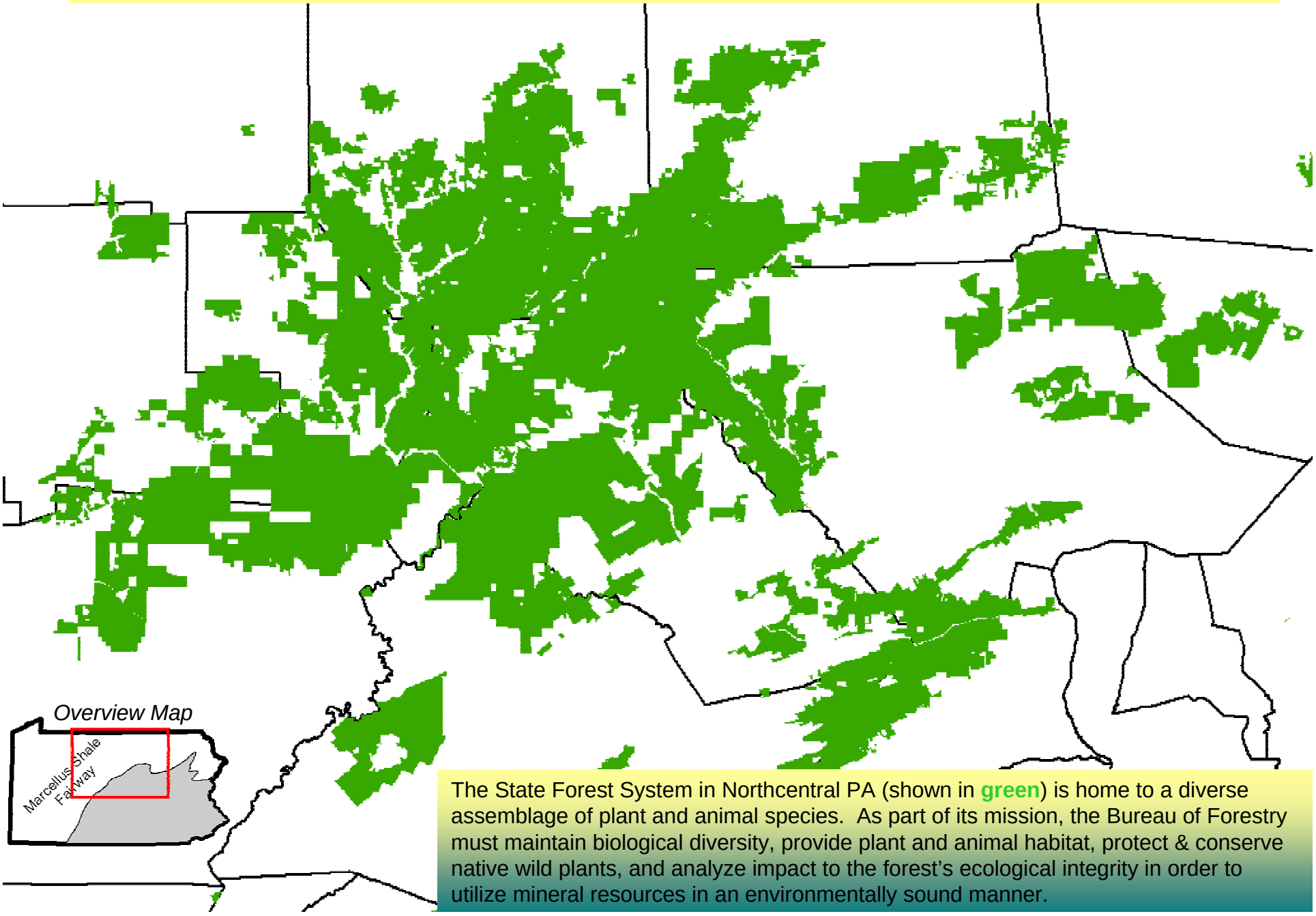
This mapping analysis demonstrates how any additional leasing involving surface disturbance upsets the sustainable balance DCNR is charged to maintain.







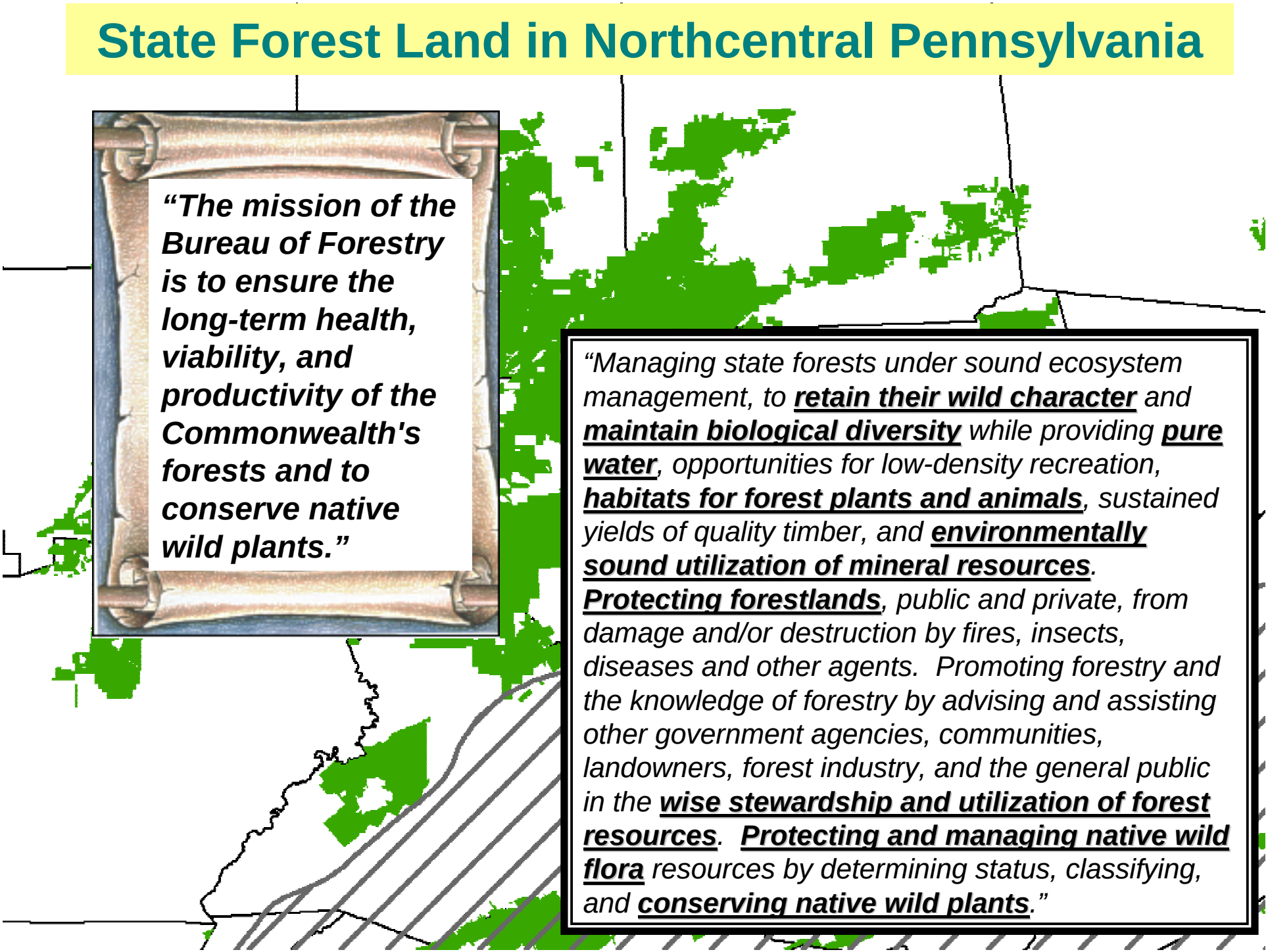
State Forest Land in North-Central Pennsylvania



Overview Map

The State Forest System in Northcentral PA (shown in **green**) is home to a diverse assemblage of plant and animal species. As part of its mission, the Bureau of Forestry must maintain biological diversity, provide plant and animal habitat, protect & conserve native wild plants, and analyze impact to the forest's ecological integrity in order to utilize mineral resources in an environmentally sound manner.

State Forest Land in Northcentral Pennsylvania



"The mission of the Bureau of Forestry is to ensure the long-term health, viability, and productivity of the Commonwealth's forests and to conserve native wild plants."

"Managing state forests under sound ecosystem management, to ***retain their wild character*** *and* ***maintain biological diversity*** *while providing* ***pure water****, opportunities for low-density recreation,* ***habitats for forest plants and animals****, sustained yields of quality timber, and* ***environmentally sound utilization of mineral resources****.* ***Protecting forestlands****, public and private, from damage and/or destruction by fires, insects, diseases and other agents. Promoting forestry and the knowledge of forestry by advising and assisting other government agencies, communities, landowners, forest industry, and the general public in the* ***wise stewardship and utilization of forest resources****.* ***Protecting and managing native wild flora*** *resources by determining status, classifying, and* ***conserving native wild plants****."*

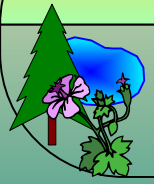
Maintaining the Forest's Ecological Integrity

Species of Concern



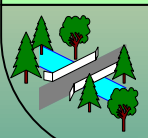
Native Biological Diversity
Threatened / Endangered Spp.
Rare / Declining Spp.

Unique Areas



Wild & Natural Areas
Steep, Wet, & Rocky Areas
Old Growth
Wild Plant Sanctuaries

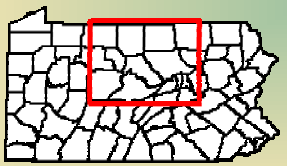
Road, Trail, & Stream Buffers

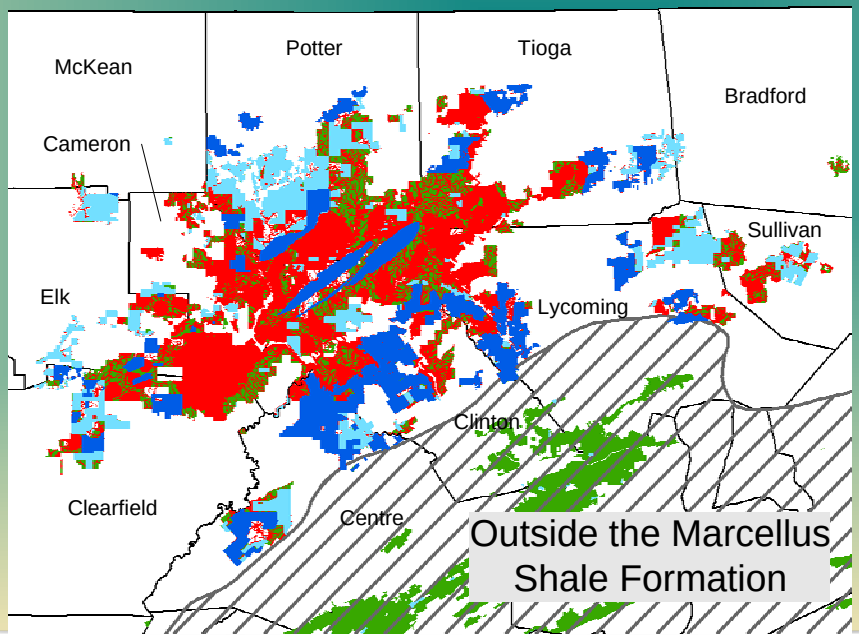


Aesthetics / Scenery
Corridors
Connectivity
Water Quality

Legend

- DCNR Gas Lease
- Severed Rights
- Ecologically Sensitive
- Other State Forest





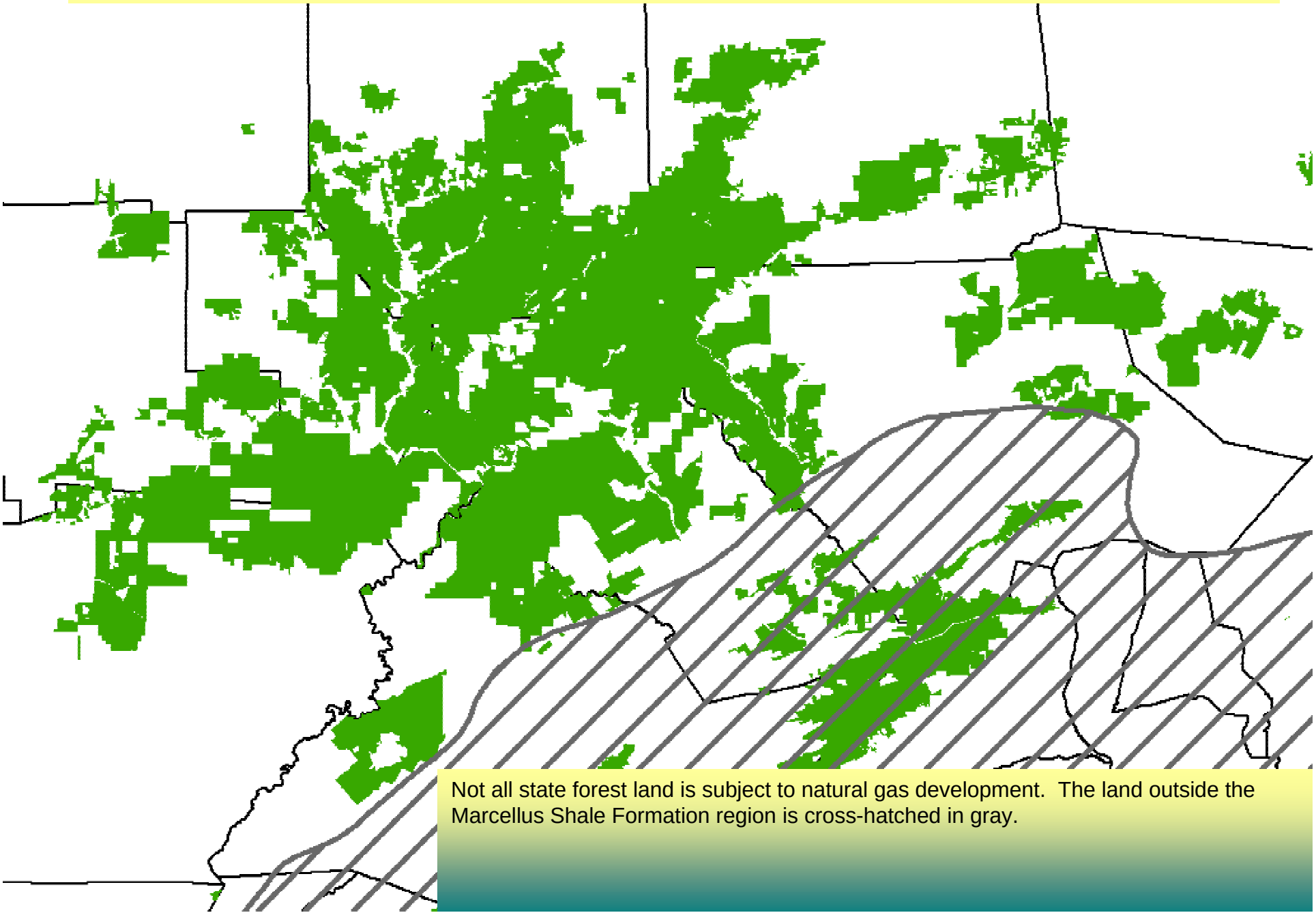
State Forest Land in the Marcellus Shale Region — 1,500,000 acres

State Forest Land Currently Leased or Severed — - 700,000 acres

Unleased Land in Ecologically Sensitive Areas — - 702,500 acres

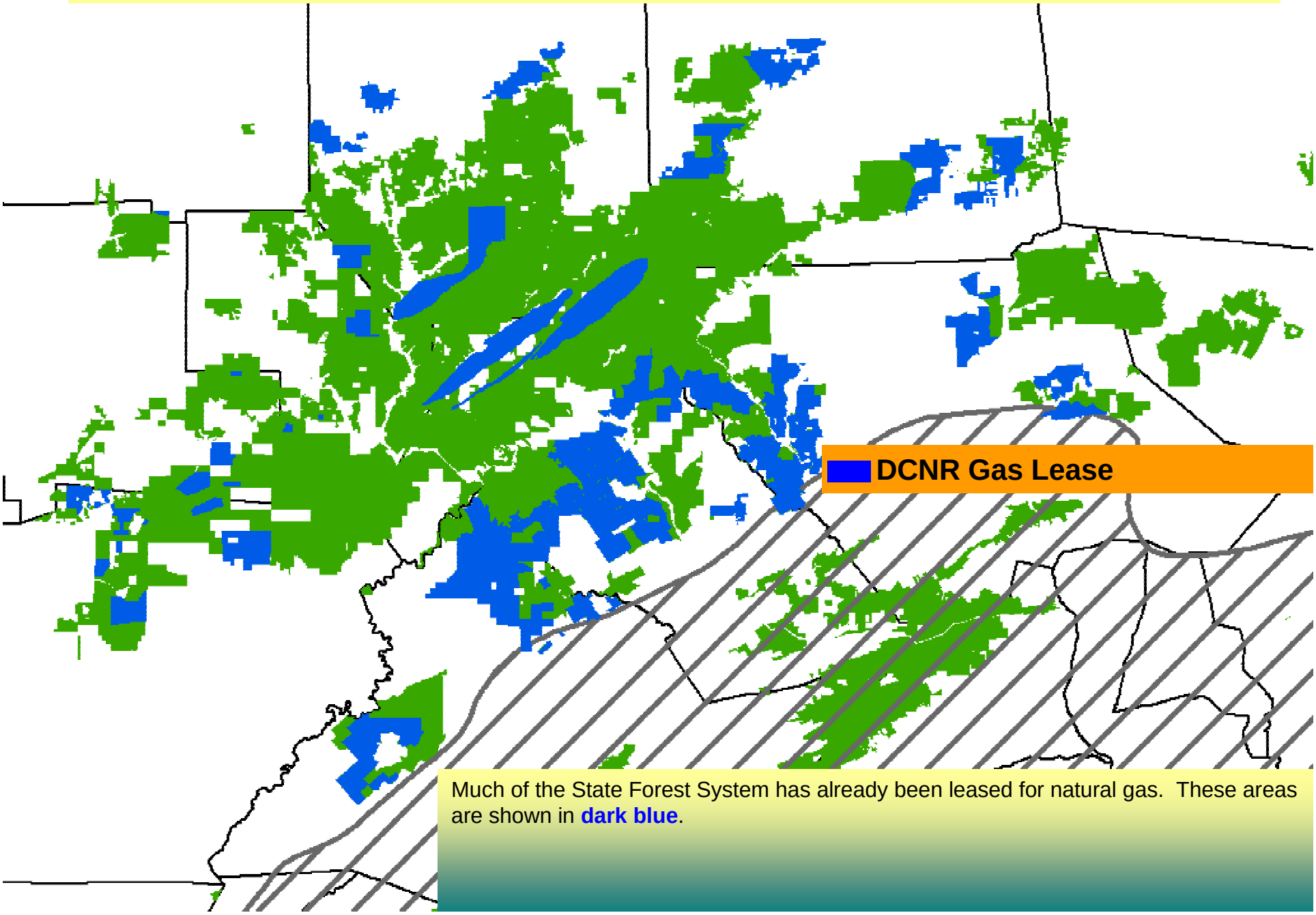
Inaccessible w/o Damaging Ecologically Sensitive Areas — **97,500** acres

Maintaining the Forest's Ecological Integrity



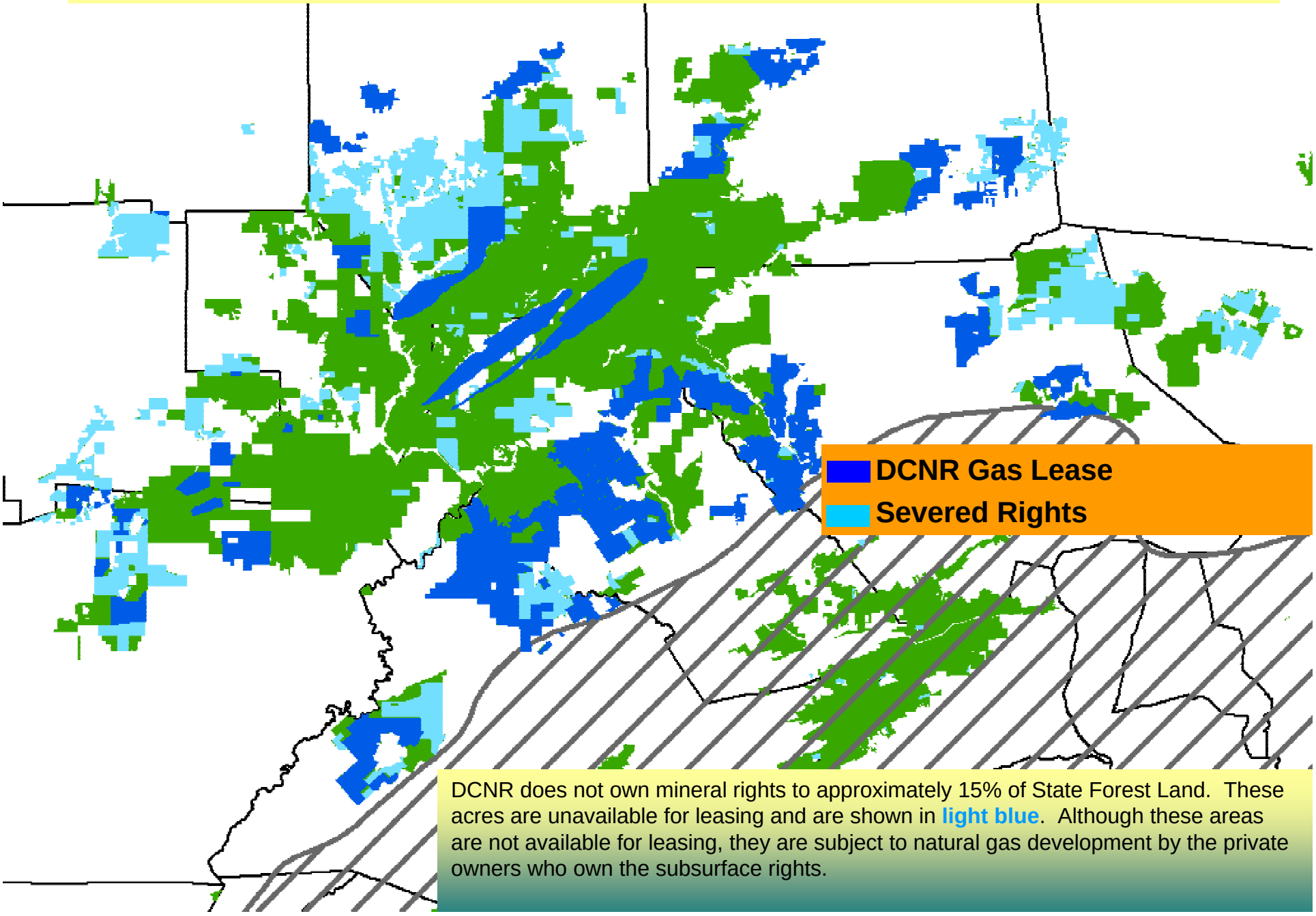
Not all state forest land is subject to natural gas development. The land outside the Marcellus Shale Formation region is cross-hatched in gray.

Maintaining the Forest's Ecological Integrity



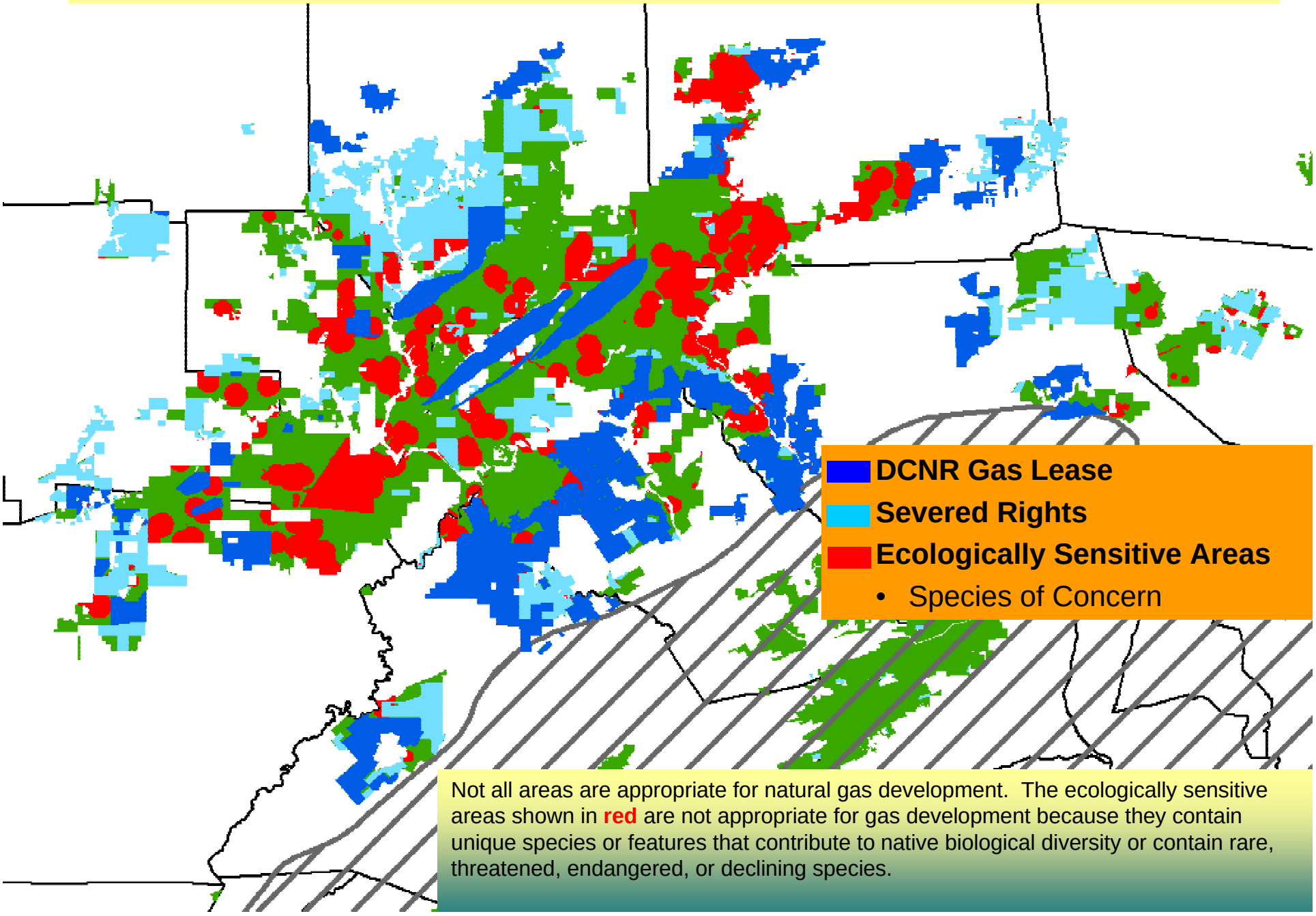
Much of the State Forest System has already been leased for natural gas. These areas are shown in **dark blue**.

Maintaining the Forest's Ecological Integrity



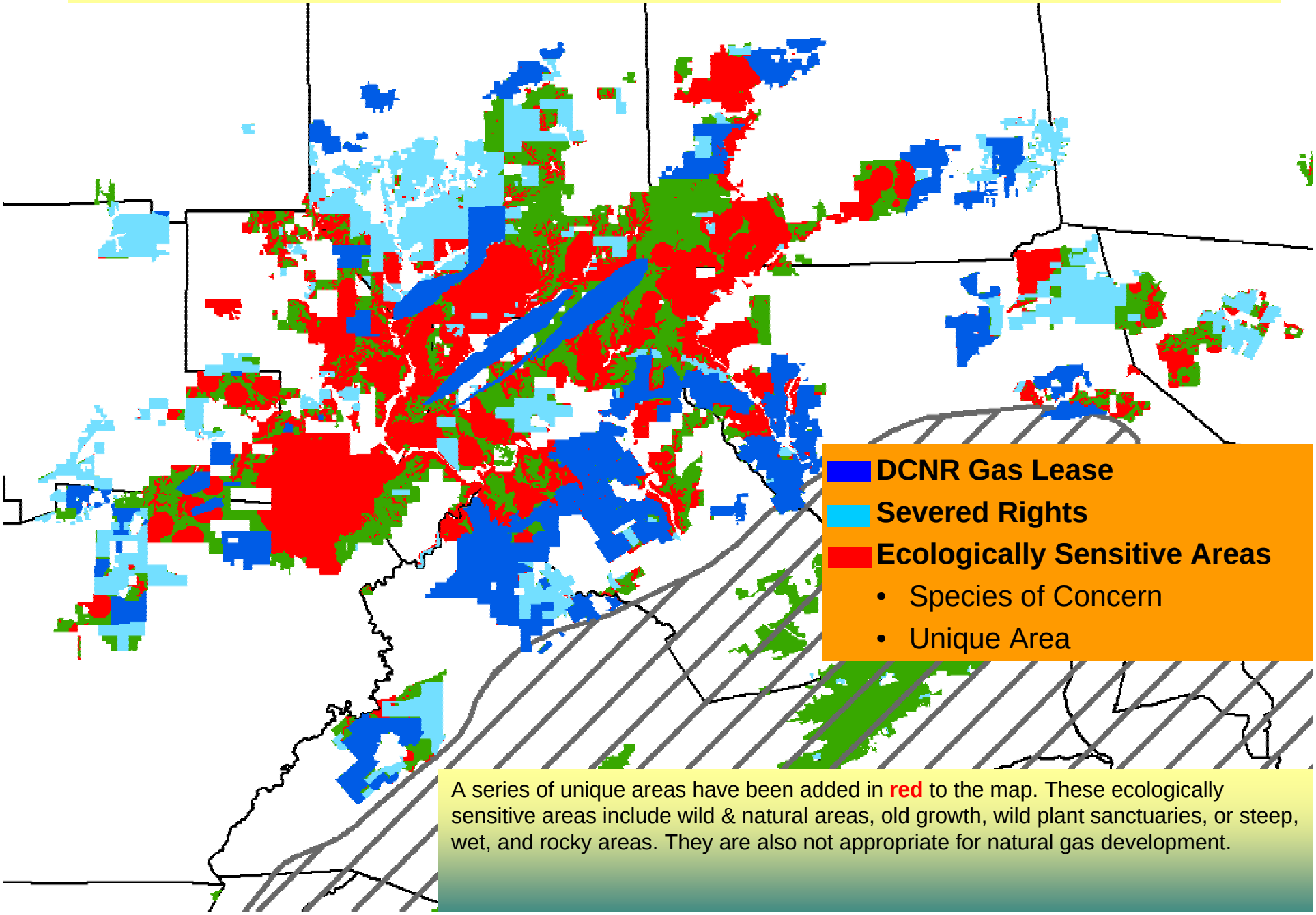
DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Maintaining the Forest's Ecological Integrity



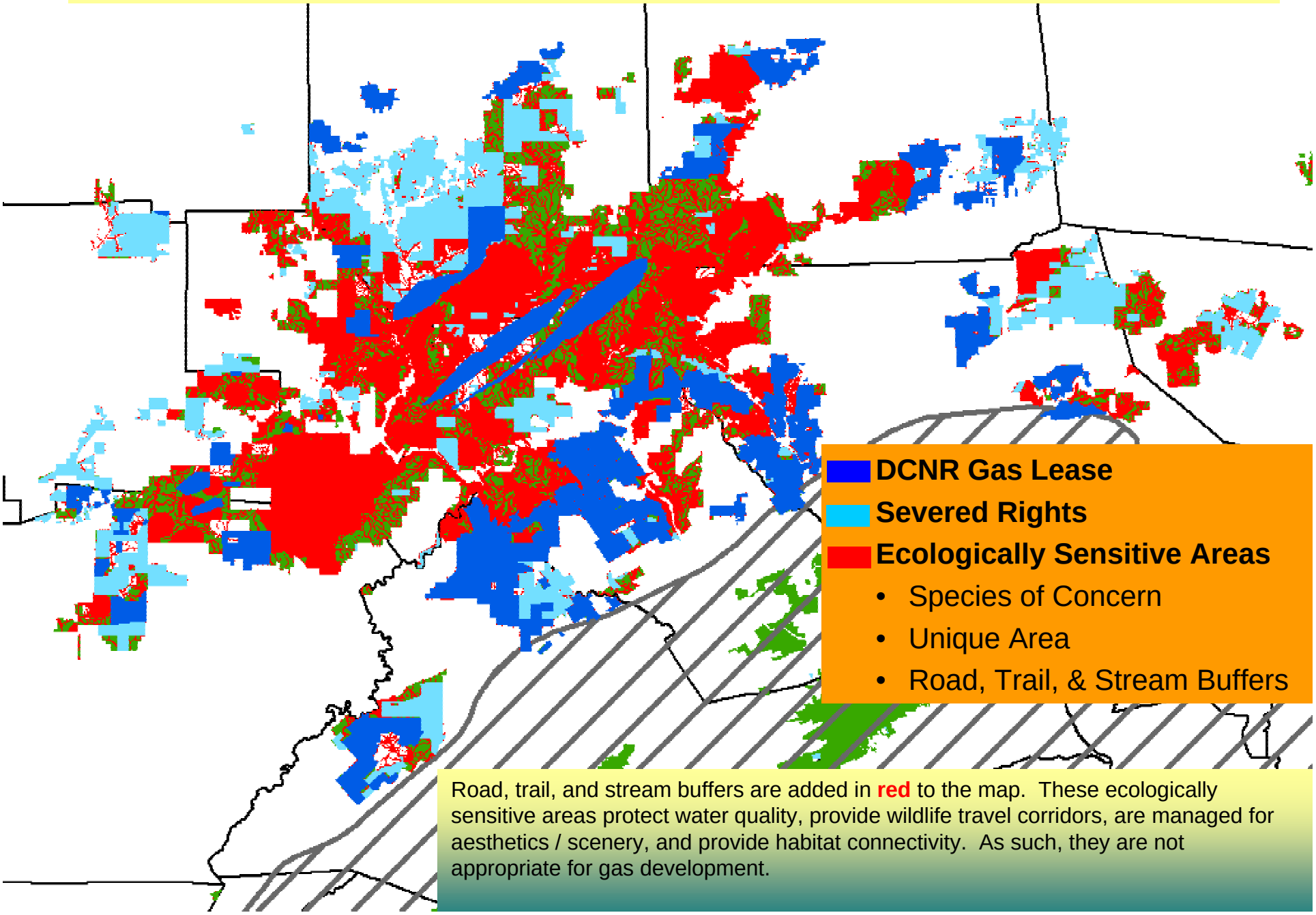
Not all areas are appropriate for natural gas development. The ecologically sensitive areas shown in **red** are not appropriate for gas development because they contain unique species or features that contribute to native biological diversity or contain rare, threatened, endangered, or declining species.

Maintaining the Forest's Ecological Integrity



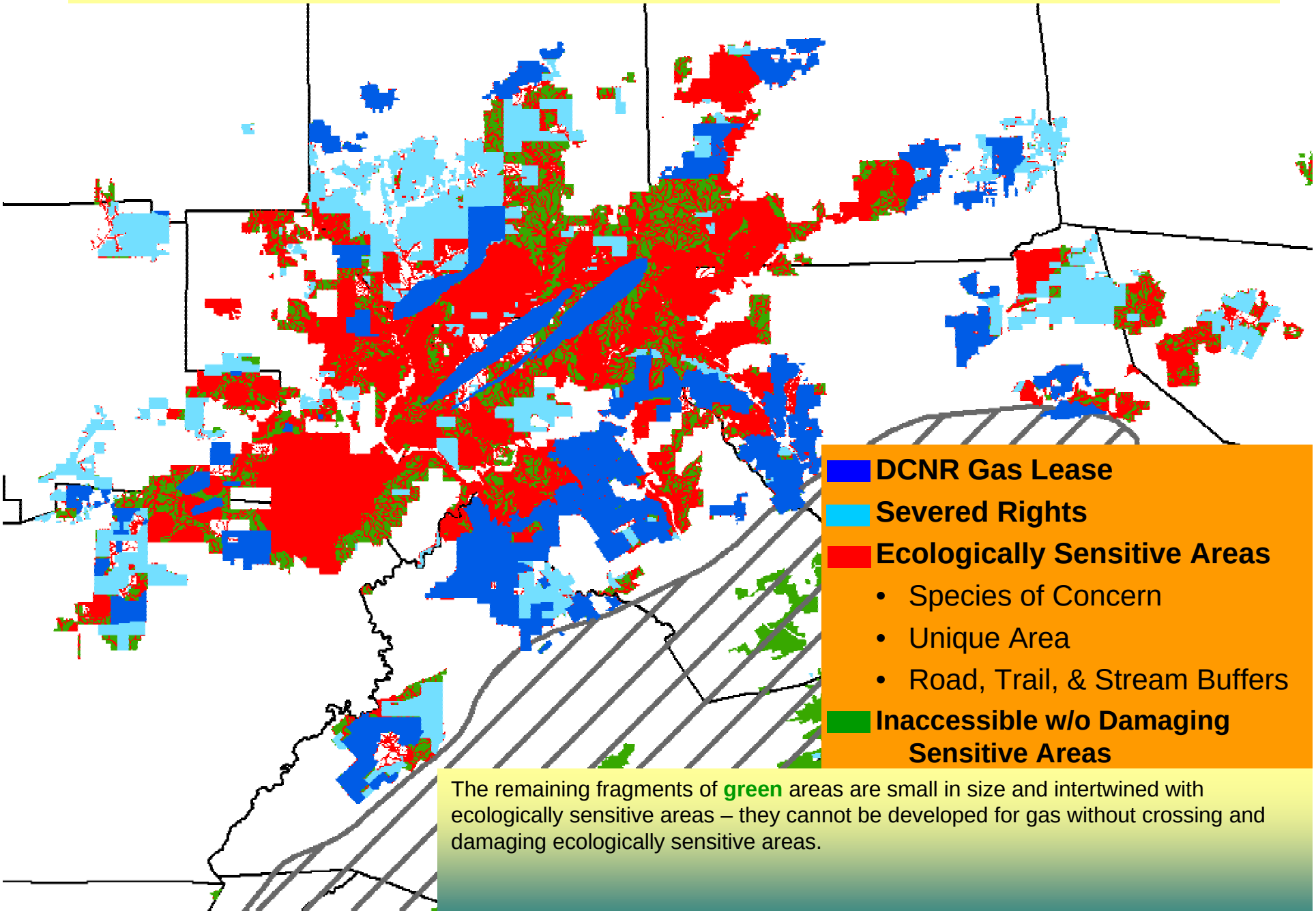
A series of unique areas have been added in **red** to the map. These ecologically sensitive areas include wild & natural areas, old growth, wild plant sanctuaries, or steep, wet, and rocky areas. They are also not appropriate for natural gas development.

Maintaining the Forest's Ecological Integrity



Road, trail, and stream buffers are added in **red** to the map. These ecologically sensitive areas protect water quality, provide wildlife travel corridors, are managed for aesthetics / scenery, and provide habitat connectivity. As such, they are not appropriate for gas development.

Maintaining the Forest's Ecological Integrity



The remaining fragments of **green** areas are small in size and intertwined with ecologically sensitive areas – they cannot be developed for gas without crossing and damaging ecologically sensitive areas.

Maintaining the Forest's Wild Character

No Management

Intense Management

Primitive



- Peace, Solitude, Remoteness, Backland Experience
- Non-Motorized Recreation

298,093 acres

Semi-Primitive



- Moderate Probability of Experiencing Solitude
- Limited Timber & Gas Activities

412,806 acres

Semi-Developed



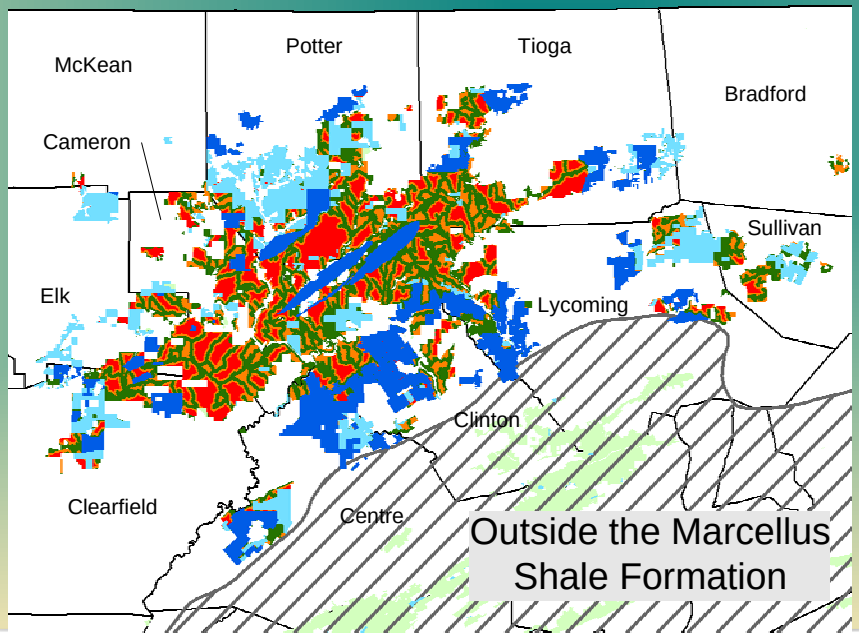
- Commonly Encounter Other Recreationists
- Motorized Recreation
- Timber & Gas Activities

706,412 acres

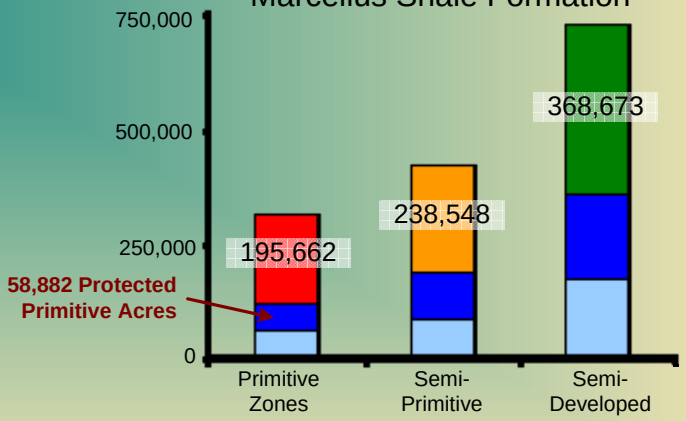
Legend

- DCNR Gas Lease
- Severed Rights
- Semi-Developed
- Semi-Primitive
- Off Limits (Primitive)



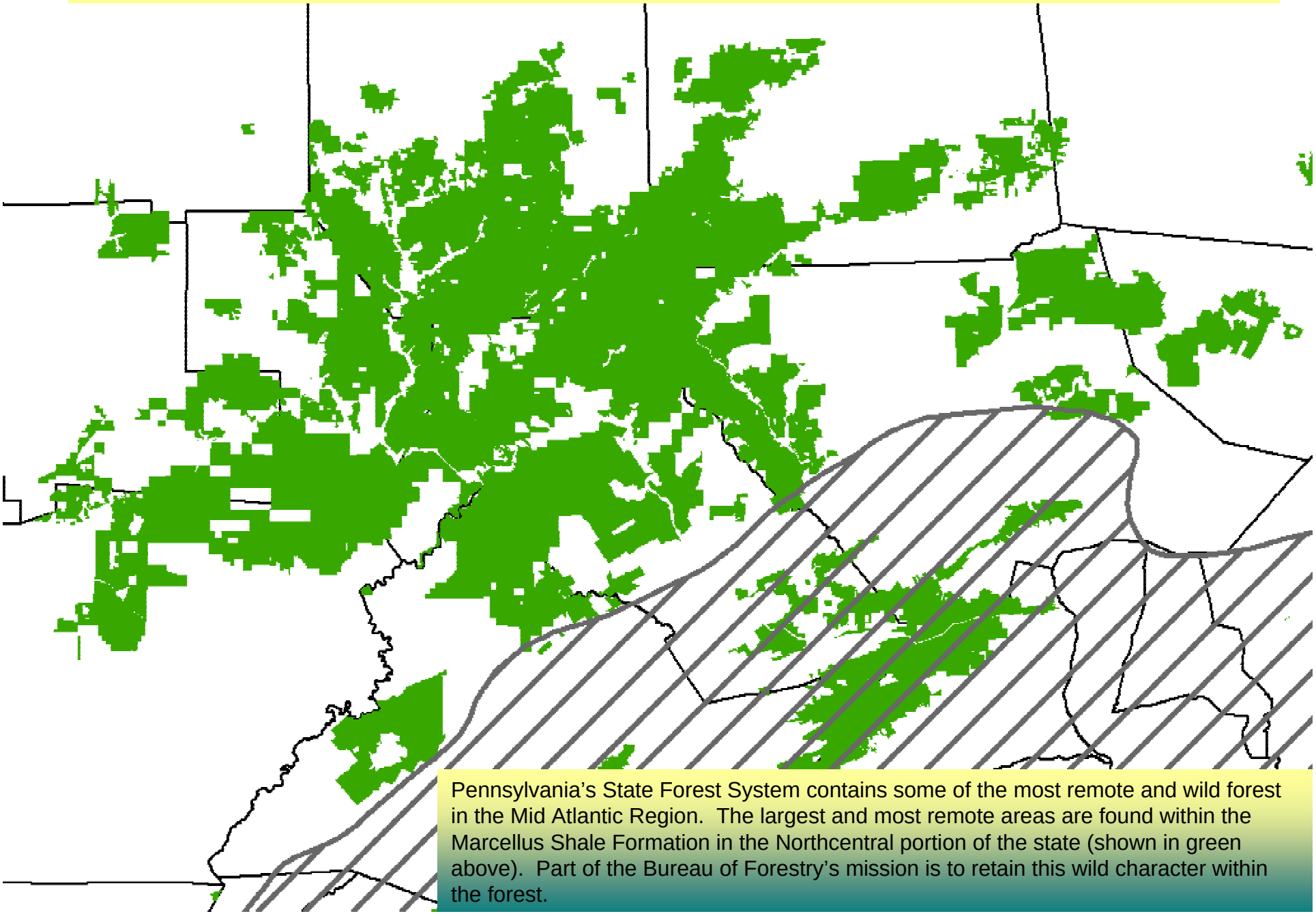


State Forest Land in the Marcellus Shale Formation*



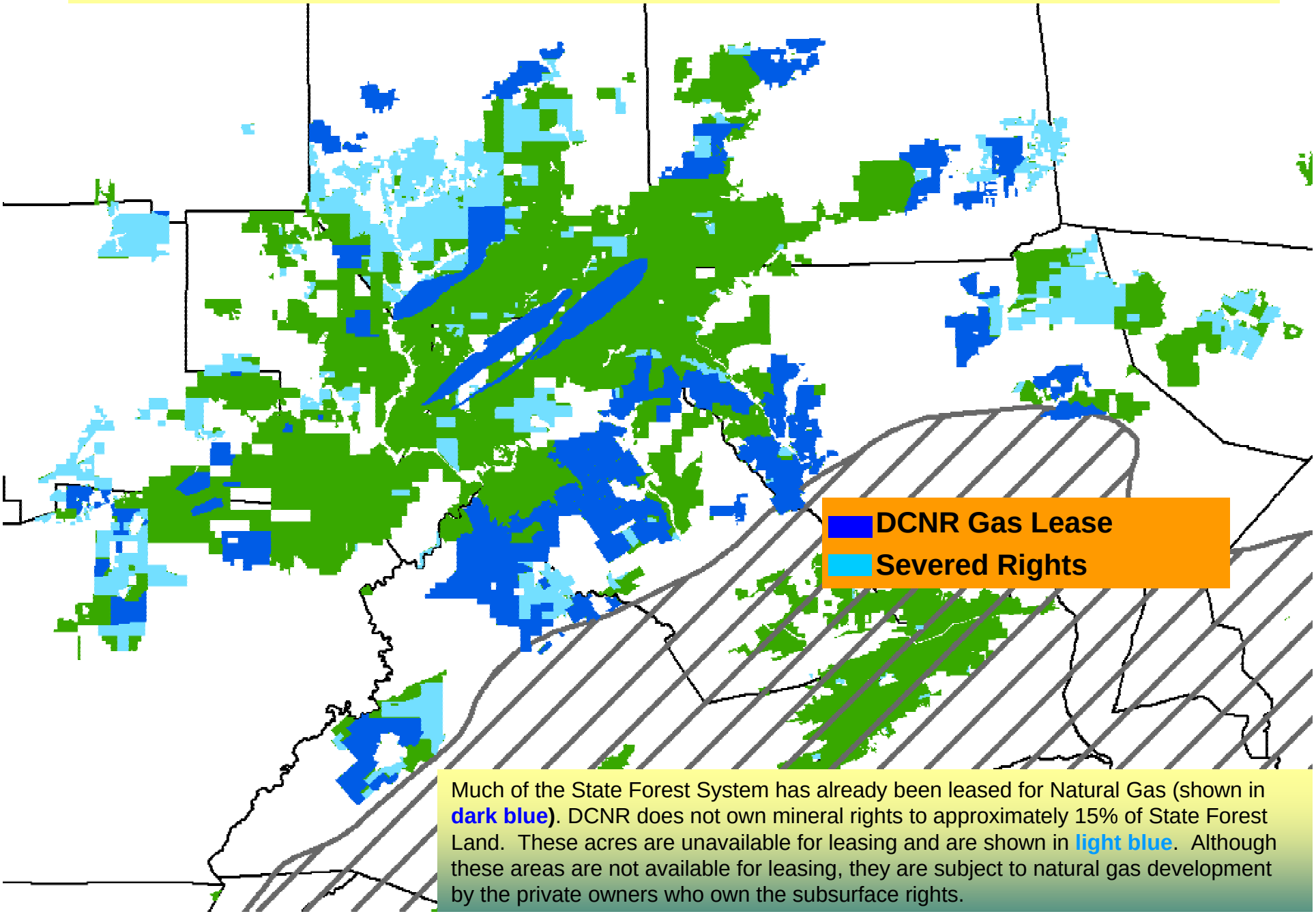
*Delaware State Forest not included.

Maintaining the Forest's Wild Character



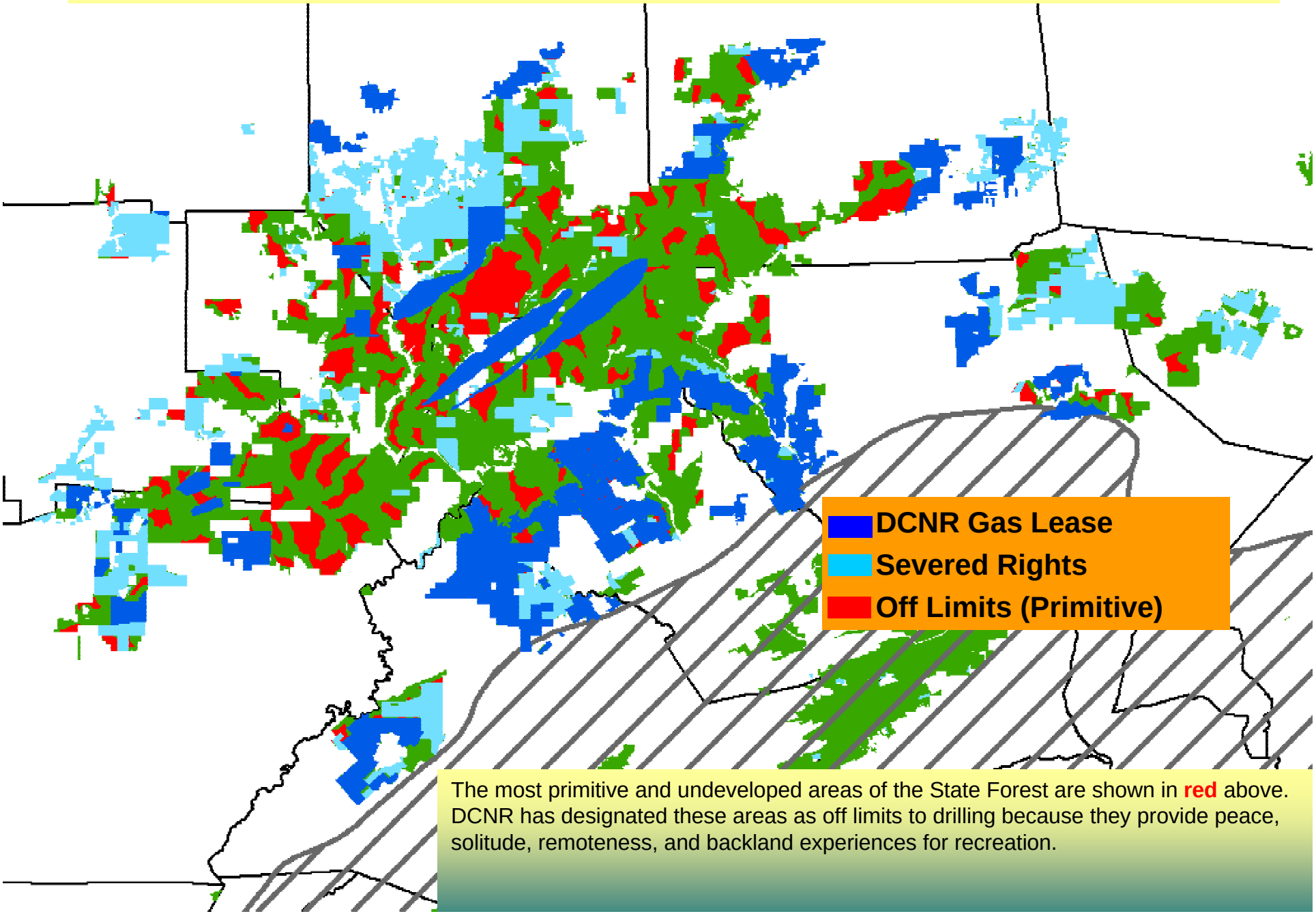
Pennsylvania's State Forest System contains some of the most remote and wild forest in the Mid Atlantic Region. The largest and most remote areas are found within the Marcellus Shale Formation in the Northcentral portion of the state (shown in green above). Part of the Bureau of Forestry's mission is to retain this wild character within the forest.

Maintaining the Forest's Wild Character



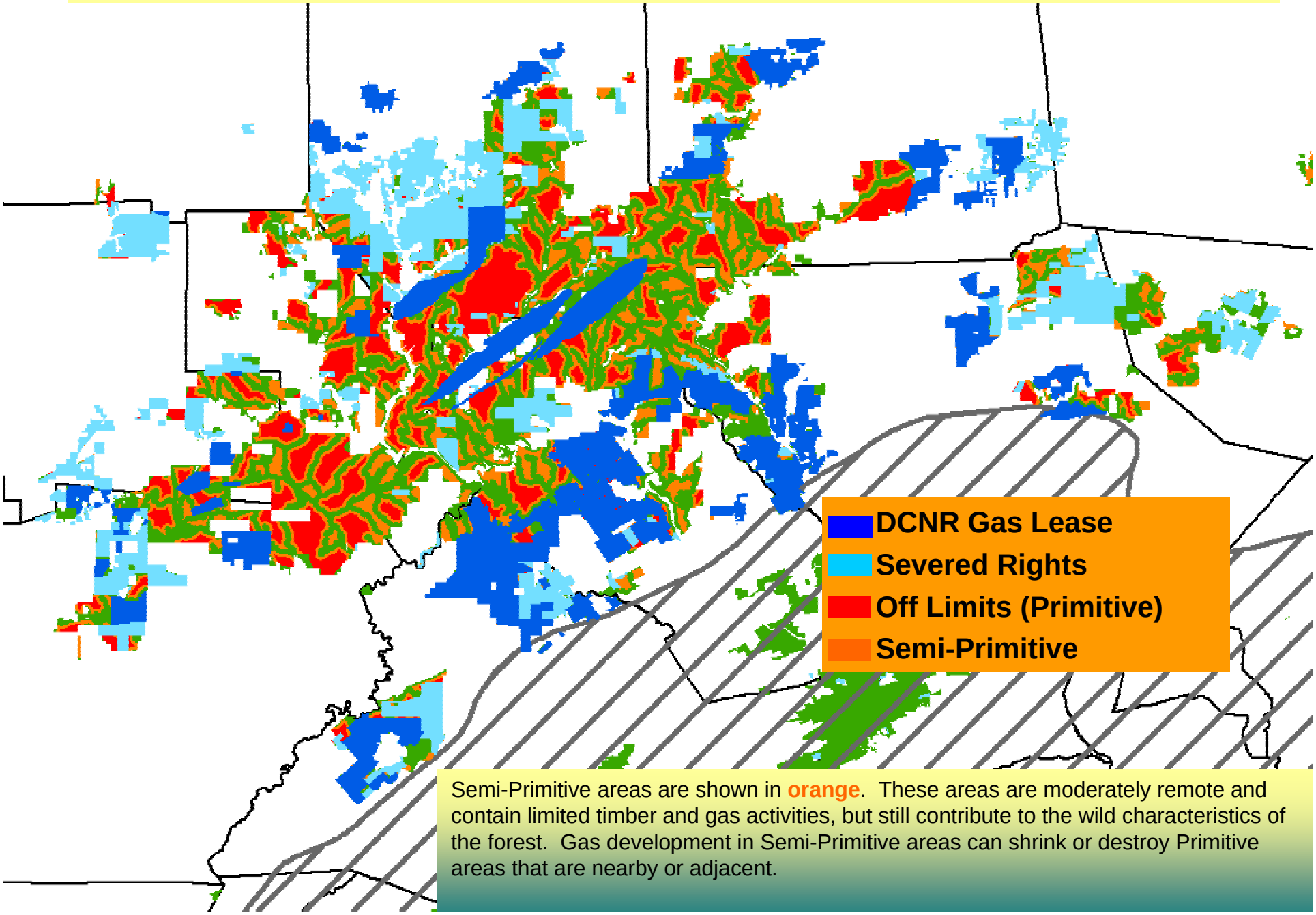
Much of the State Forest System has already been leased for Natural Gas (shown in **dark blue)**. DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Maintaining the Forest's Wild Character



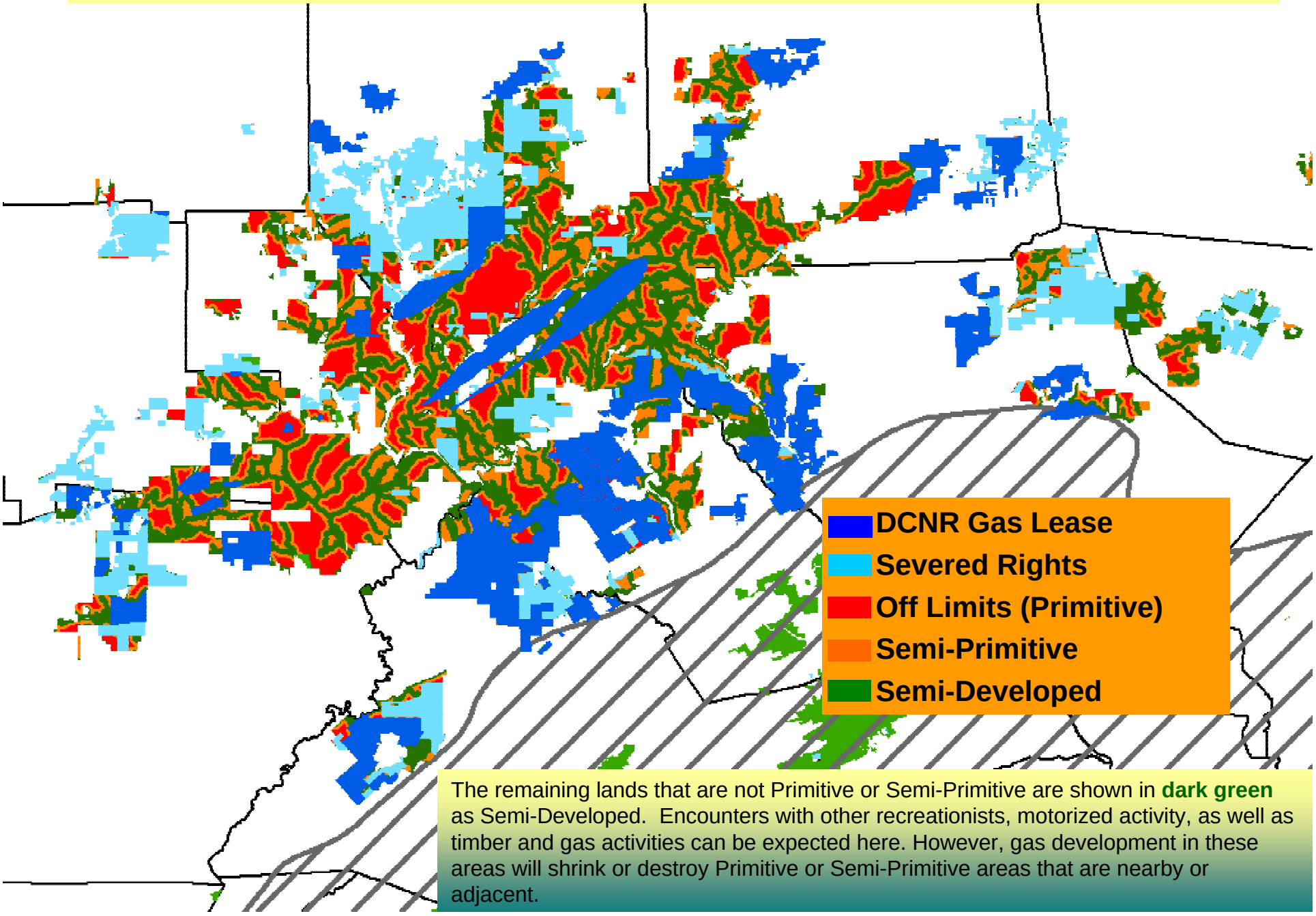
The most primitive and undeveloped areas of the State Forest are shown in **red** above. DCNR has designated these areas as off limits to drilling because they provide peace, solitude, remoteness, and backland experiences for recreation.

Maintaining the Forest's Wild Character



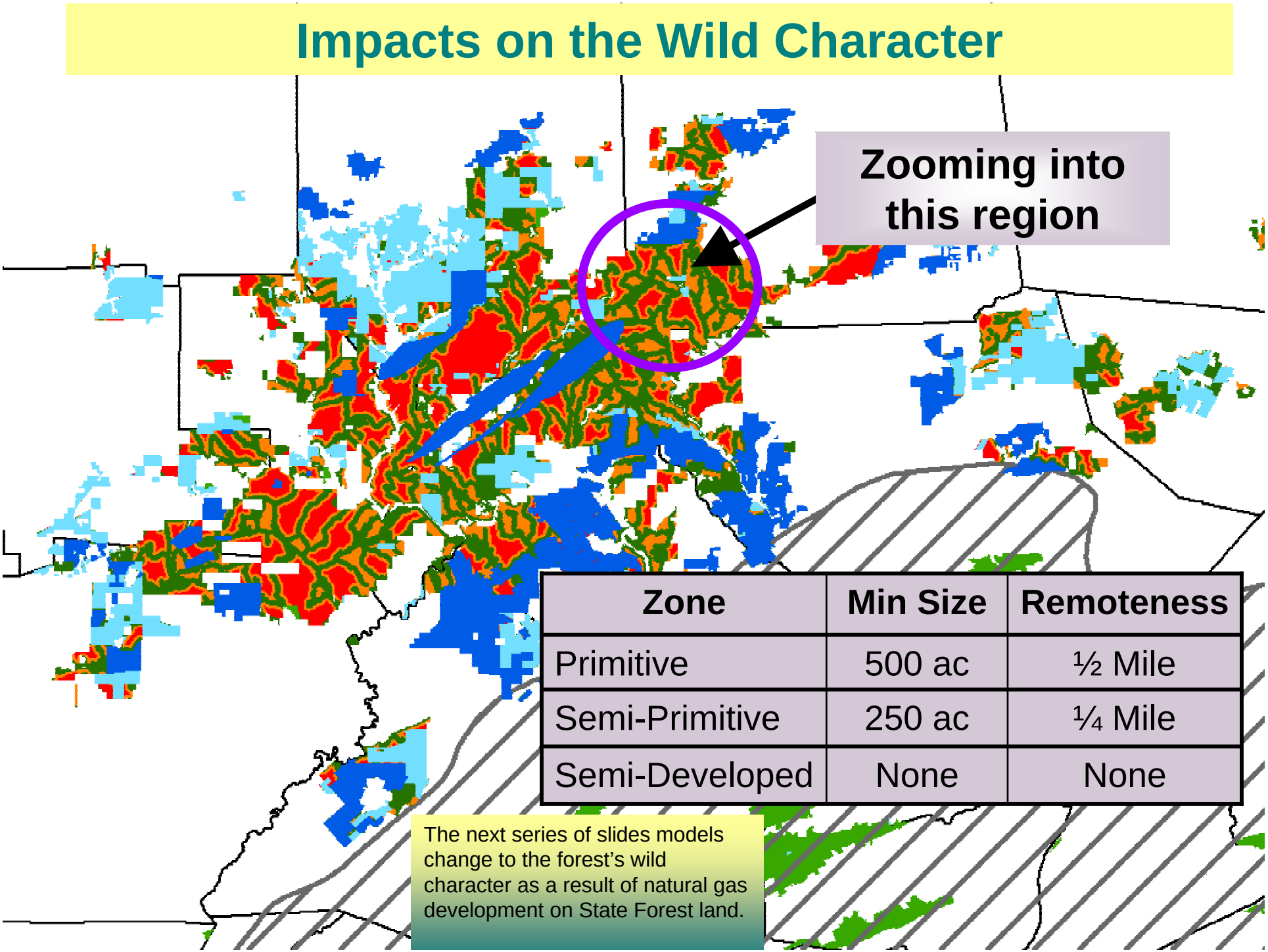
Semi-Primitive areas are shown in **orange**. These areas are moderately remote and contain limited timber and gas activities, but still contribute to the wild characteristics of the forest. Gas development in Semi-Primitive areas can shrink or destroy Primitive areas that are nearby or adjacent.

Maintaining the Forest's Wild Character



The remaining lands that are not Primitive or Semi-Primitive are shown in **dark green** as Semi-Developed. Encounters with other recreationists, motorized activity, as well as timber and gas activities can be expected here. However, gas development in these areas will shrink or destroy Primitive or Semi-Primitive areas that are nearby or adjacent.

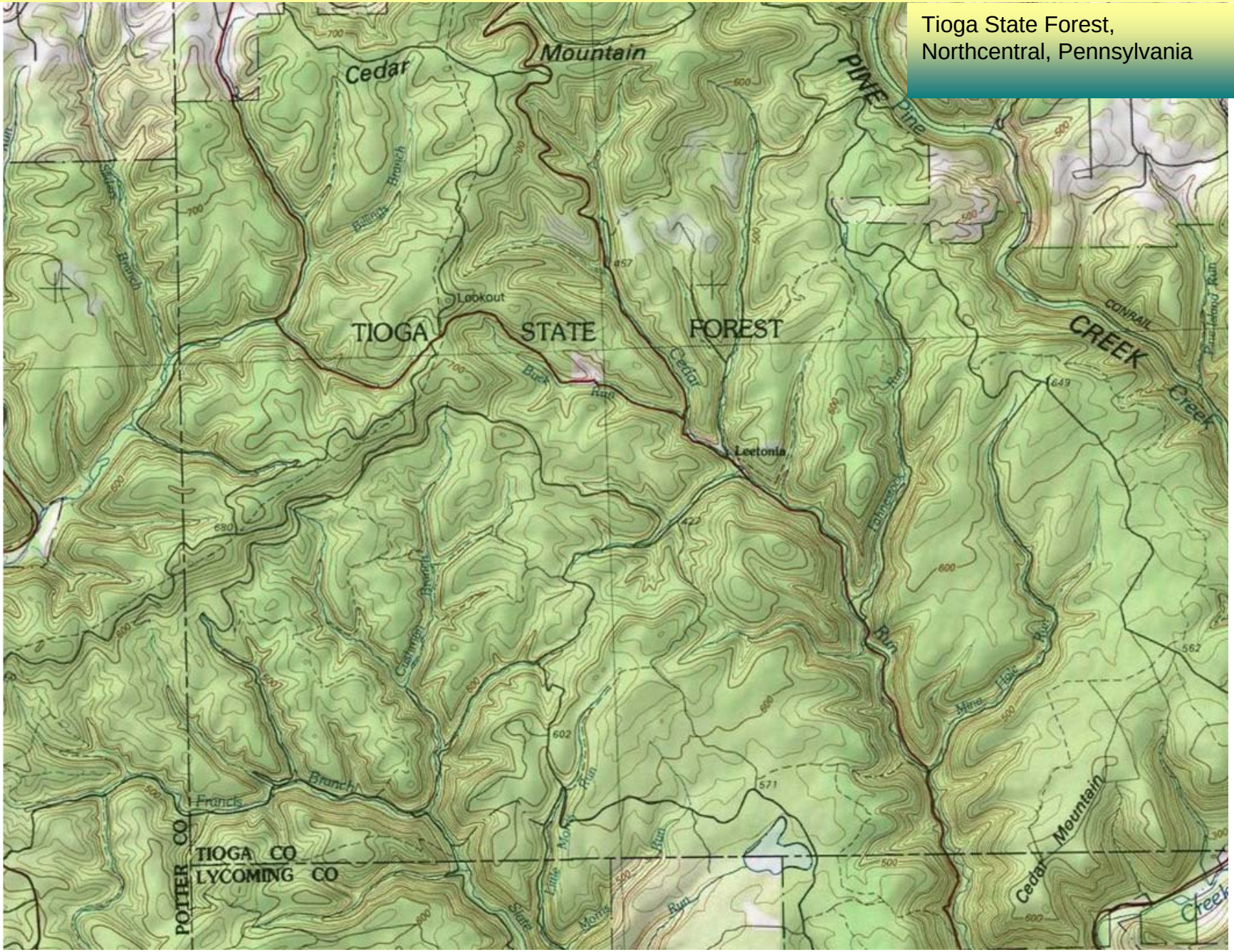
Impacts on the Wild Character



Zone	Min Size	Remoteness
Primitive	500 ac	½ Mile
Semi-Primitive	250 ac	¼ Mile
Semi-Developed	None	None

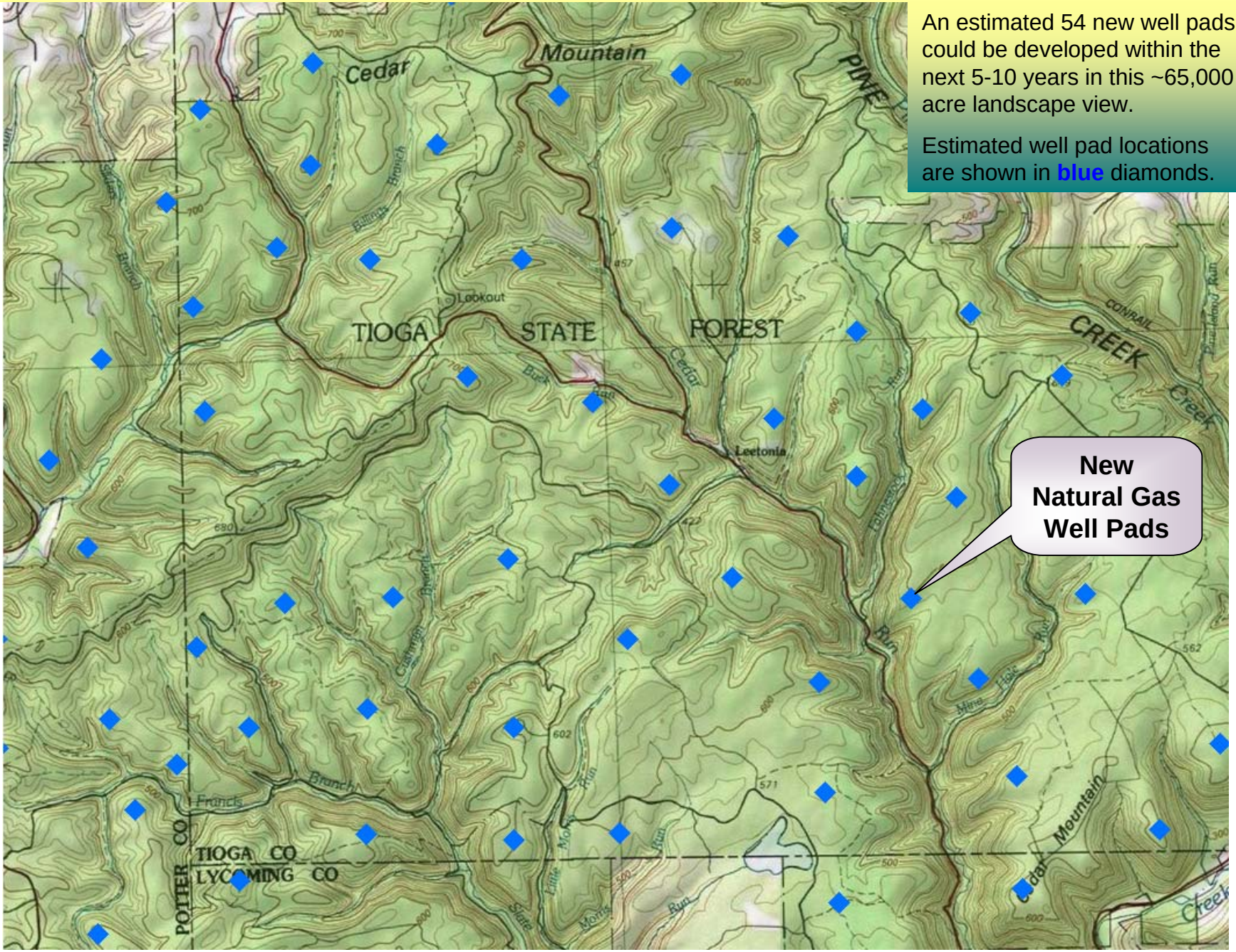
The next series of slides models change to the forest's wild character as a result of natural gas development on State Forest land.

Topography



Tioga State Forest,
Northcentral, Pennsylvania

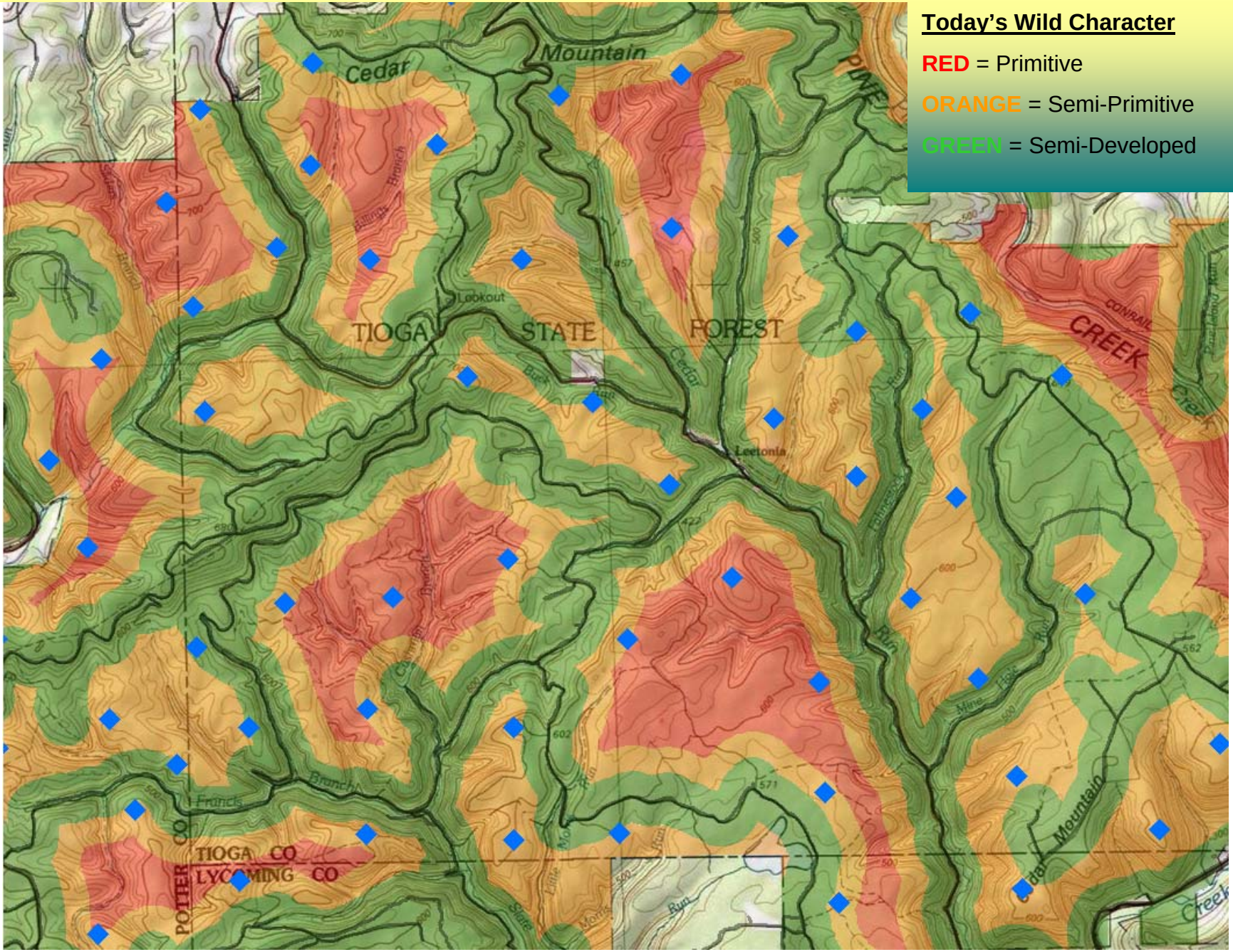
New Well Pad Locations



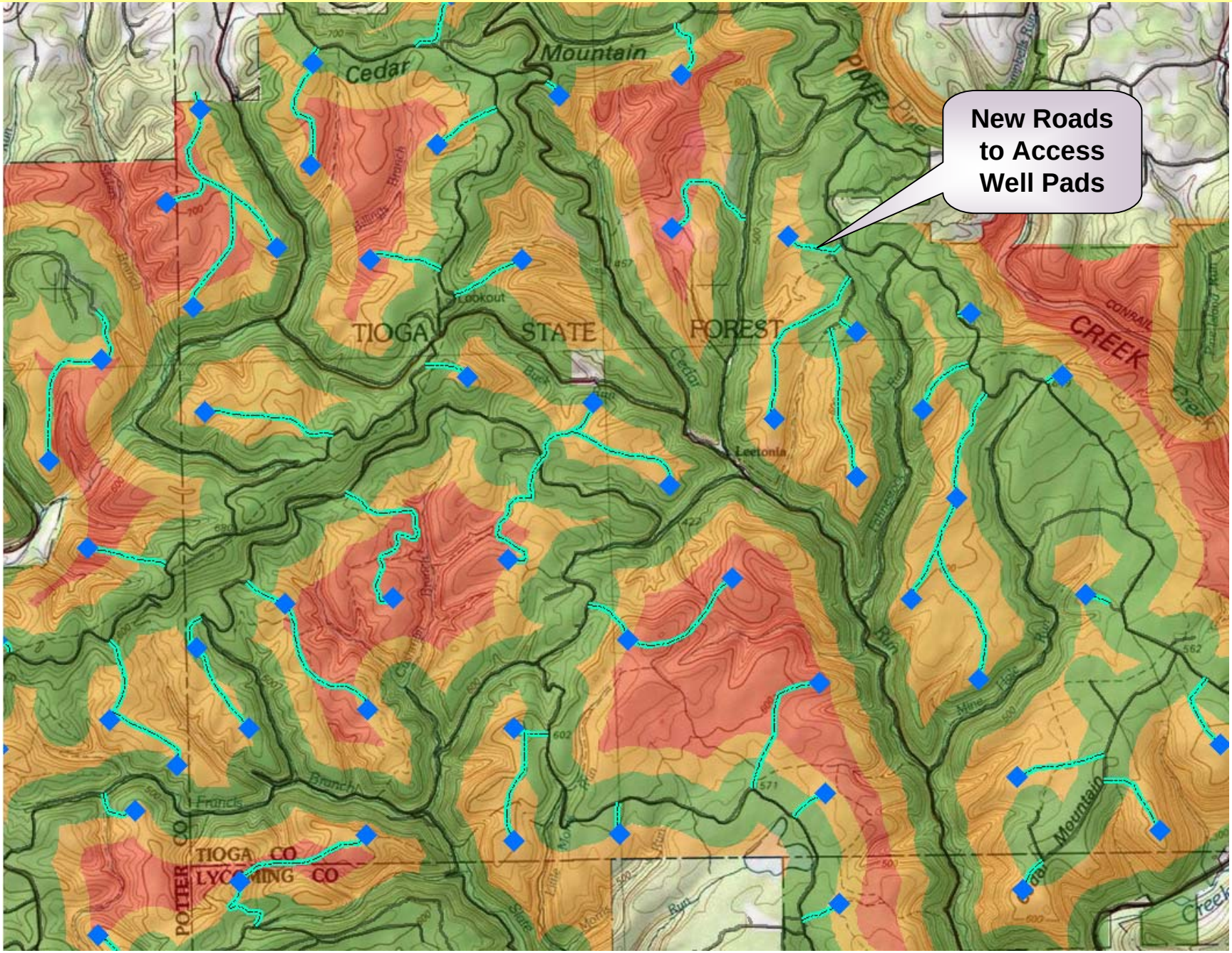
An estimated 54 new well pads could be developed within the next 5-10 years in this ~65,000 acre landscape view.

Estimated well pad locations are shown in **blue** diamonds.

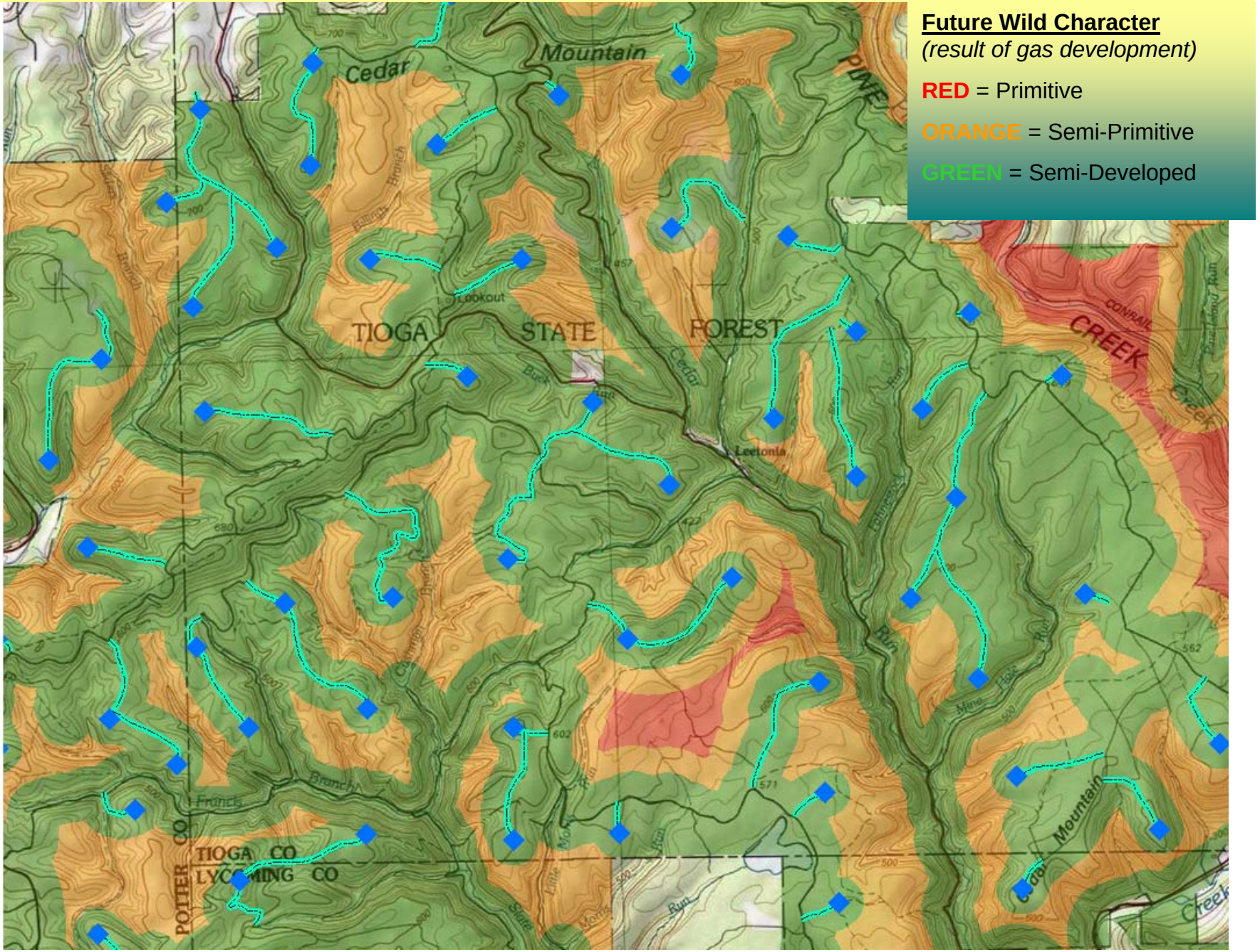
Wild Character before Well Pads



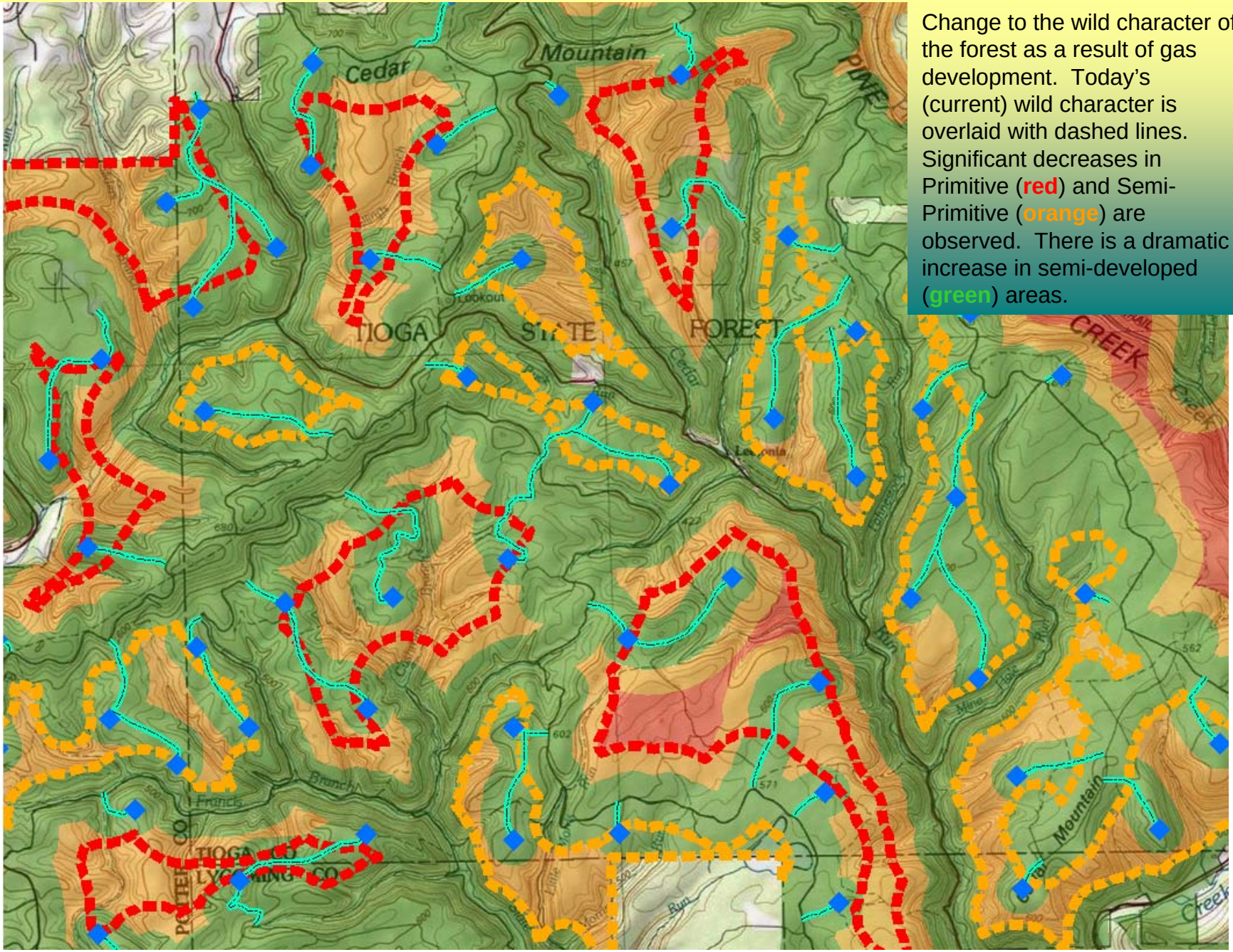
New Access Roads Required



Forest's Wild Character with New Well Pads

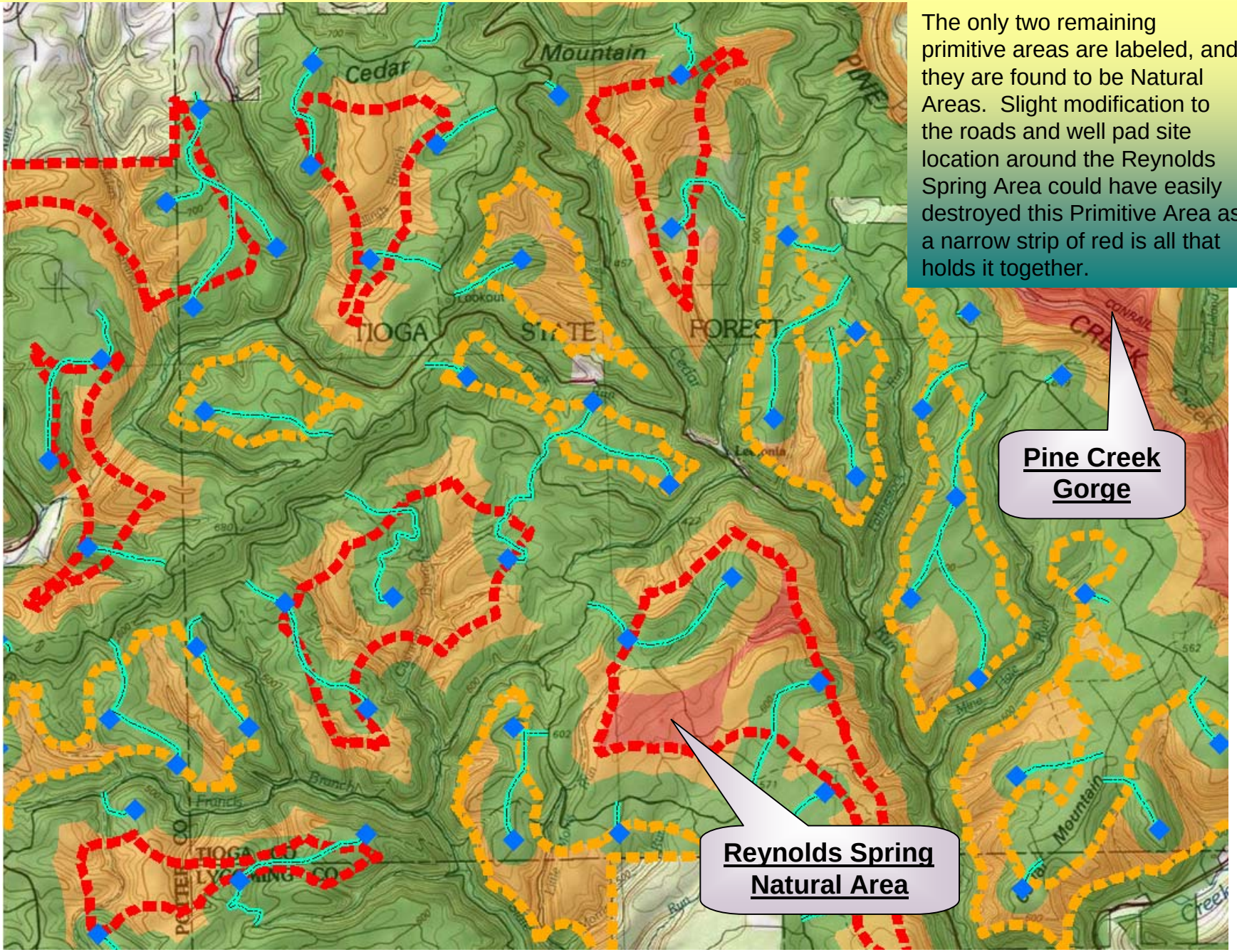


Impact on the Forest's Wild Character



Change to the wild character of the forest as a result of gas development. Today's (current) wild character is overlaid with dashed lines. Significant decreases in Primitive (**red**) and Semi-Primitive (**orange**) are observed. There is a dramatic increase in semi-developed (**green**) areas.

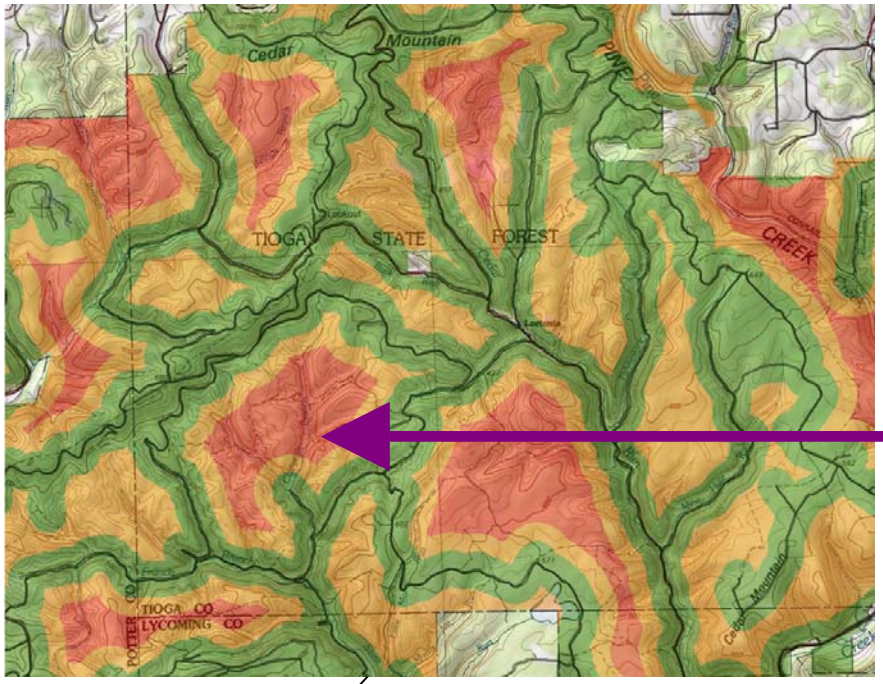
Impact on the Forest's Wild Character



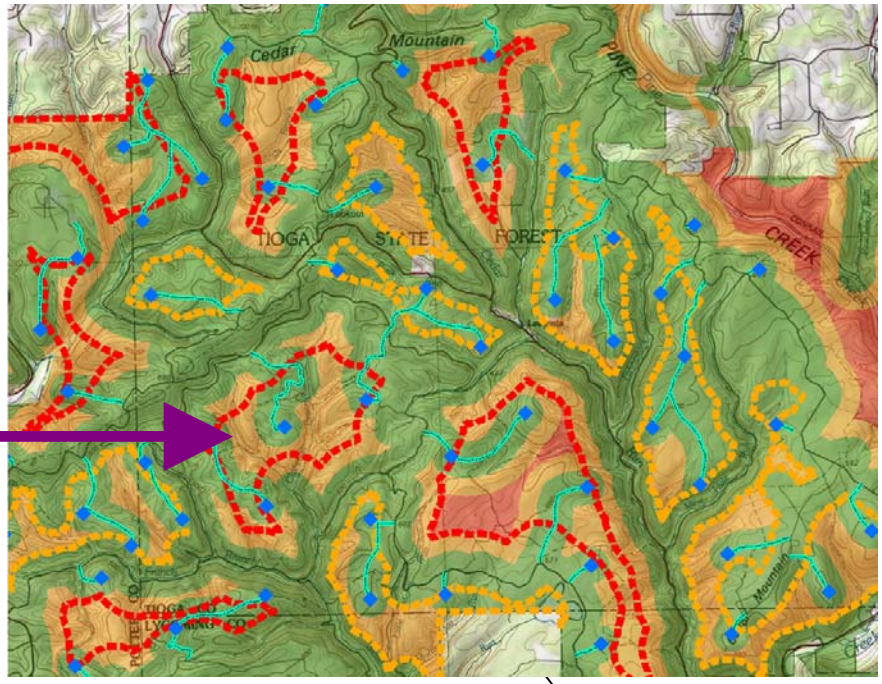
The only two remaining primitive areas are labeled, and they are found to be Natural Areas. Slight modification to the roads and well pad site location around the Reynolds Spring Area could have easily destroyed this Primitive Area as a narrow strip of red is all that holds it together.

Change in the Forest's Wild Character

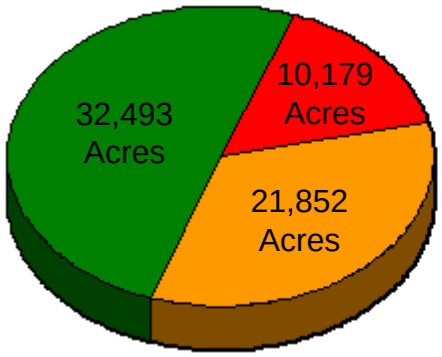
Before



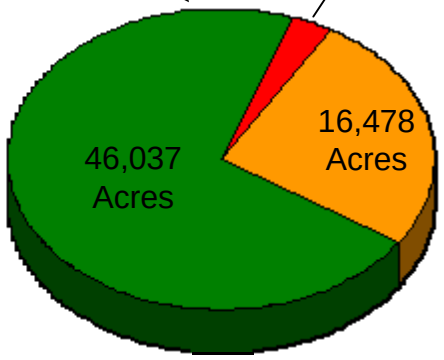
After



In this ~65,000 acre landscape view, with 54 new well pads…



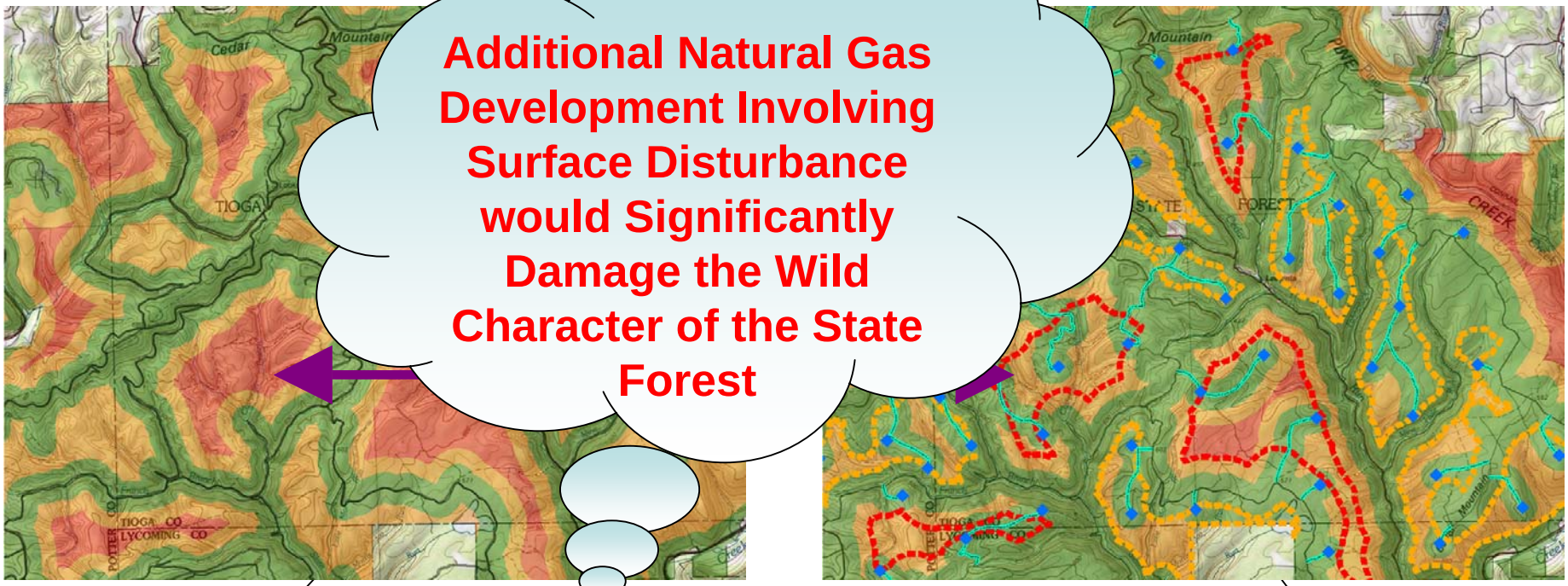
Zone	Net Gain/Loss
Primitive	-8,171
Semi-Primitive	-5,374
Semi-Developed	13,545



Modeling Change in the Forest's Wild Character

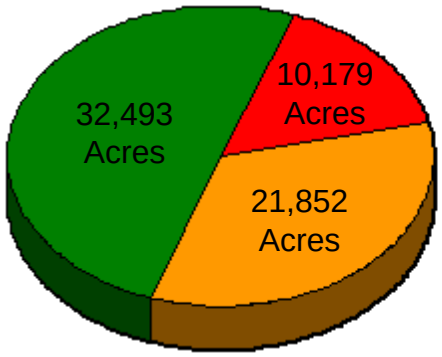
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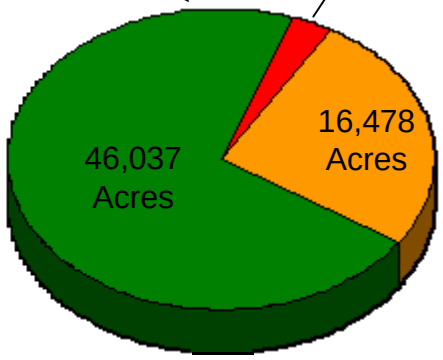
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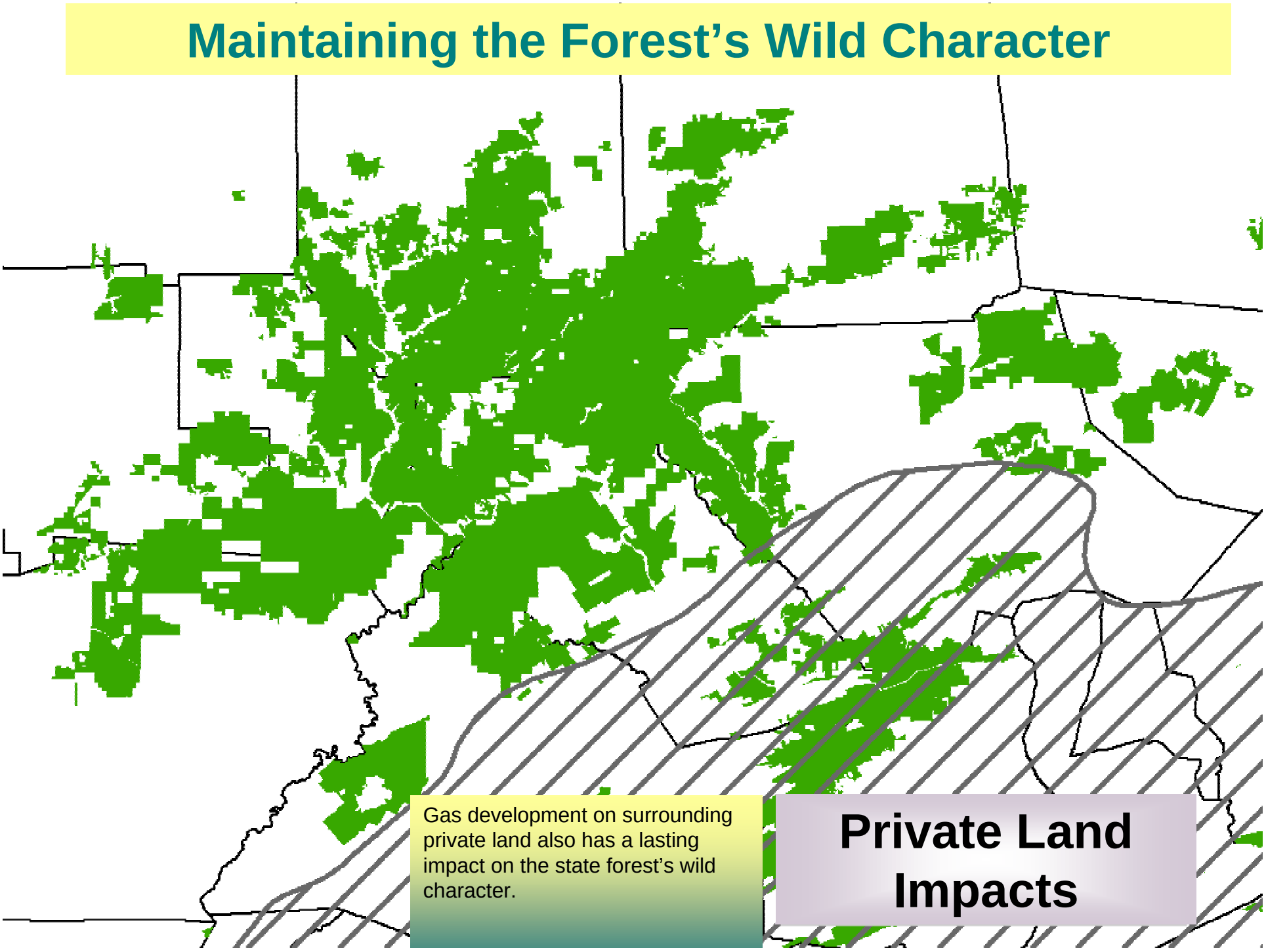
In this ~65,000 acre landscape view, with 54 new well pads…

Zone	Net Gain/Loss
Primitive	-8,171
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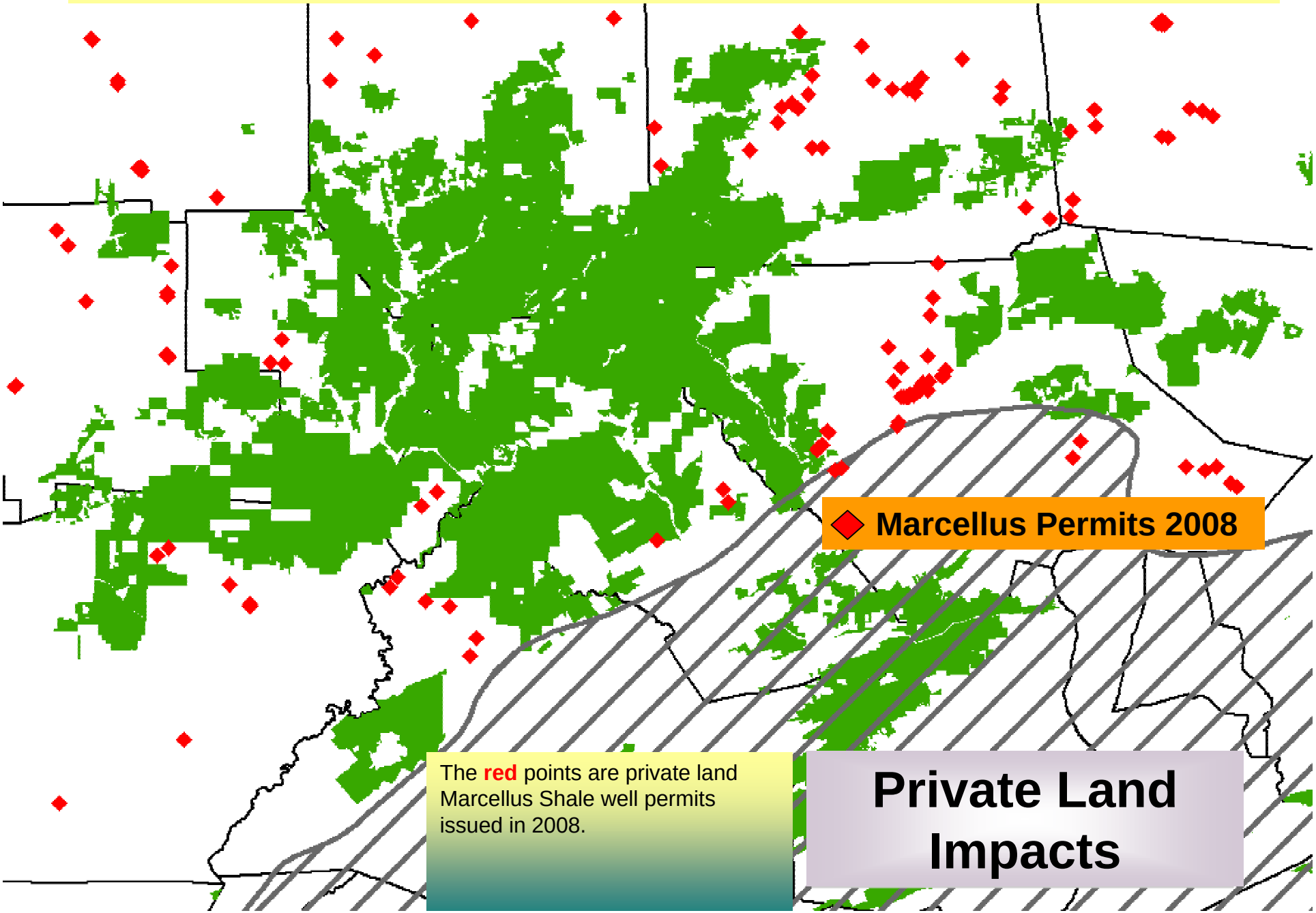
Maintaining the Forest's Wild Character



Gas development on surrounding private land also has a lasting impact on the state forest's wild character.

Private Land Impacts

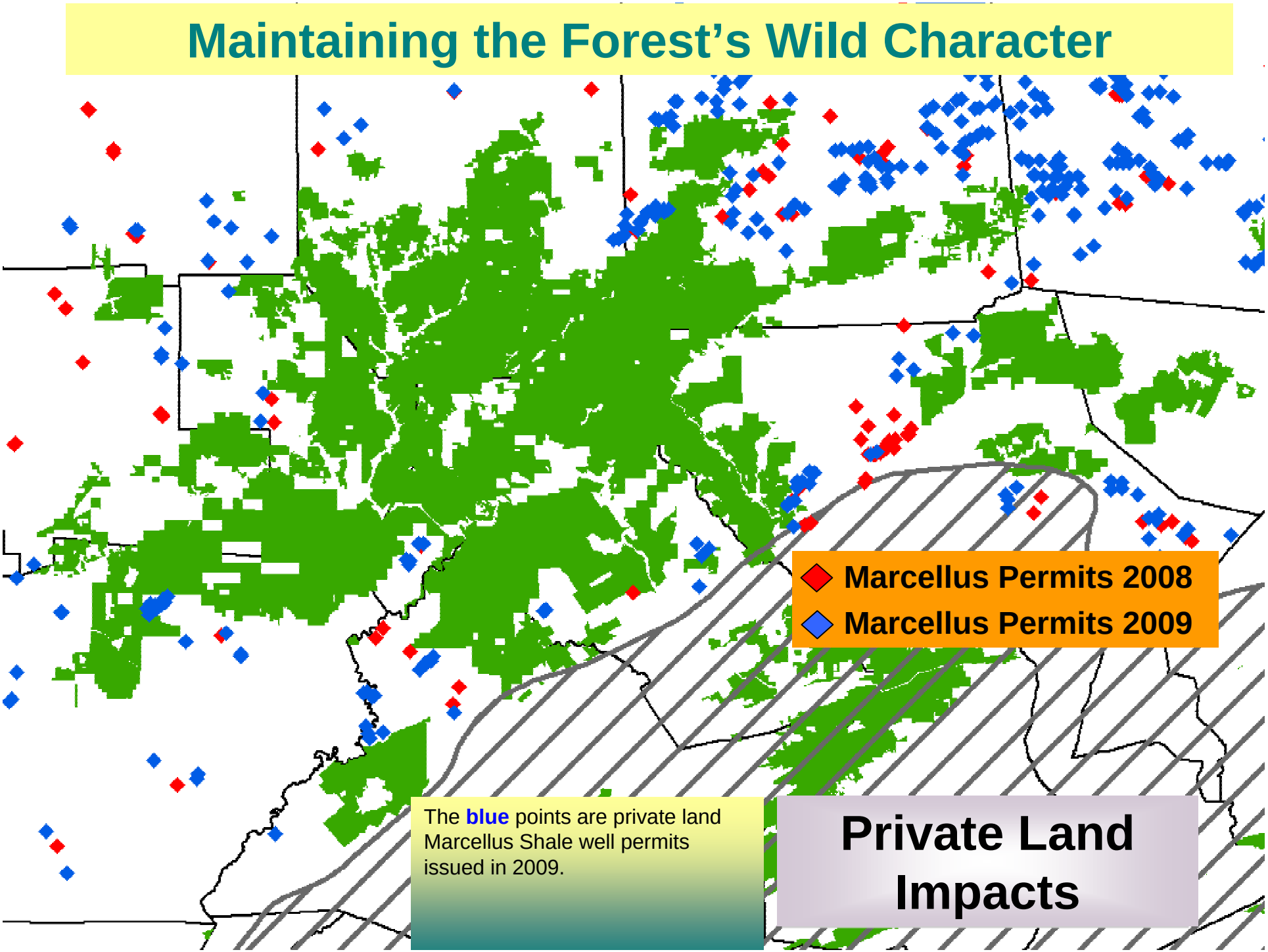
Maintaining the Forest's Wild Character



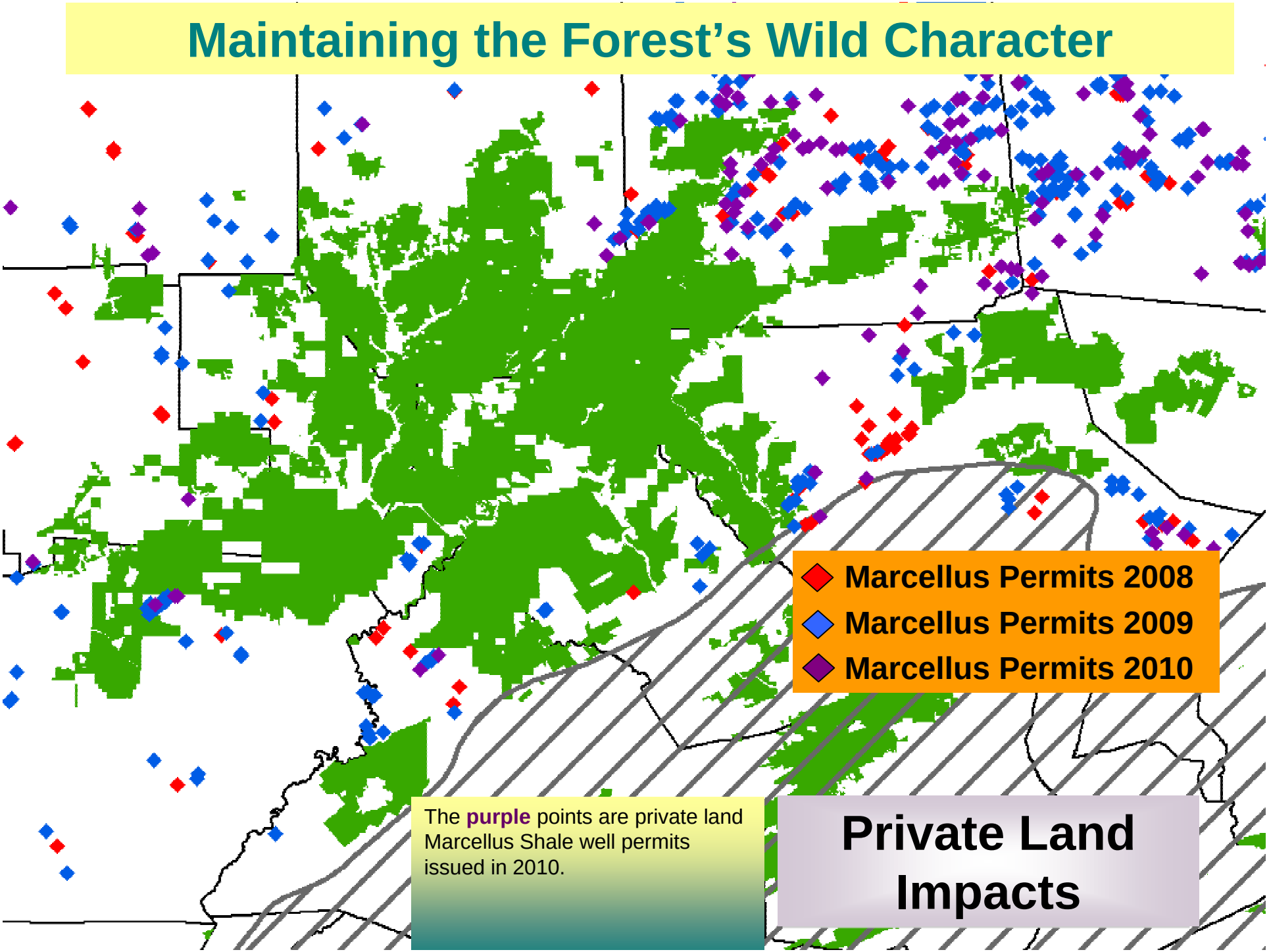
The **red** points are private land Marcellus Shale well permits issued in 2008.

Private Land Impacts

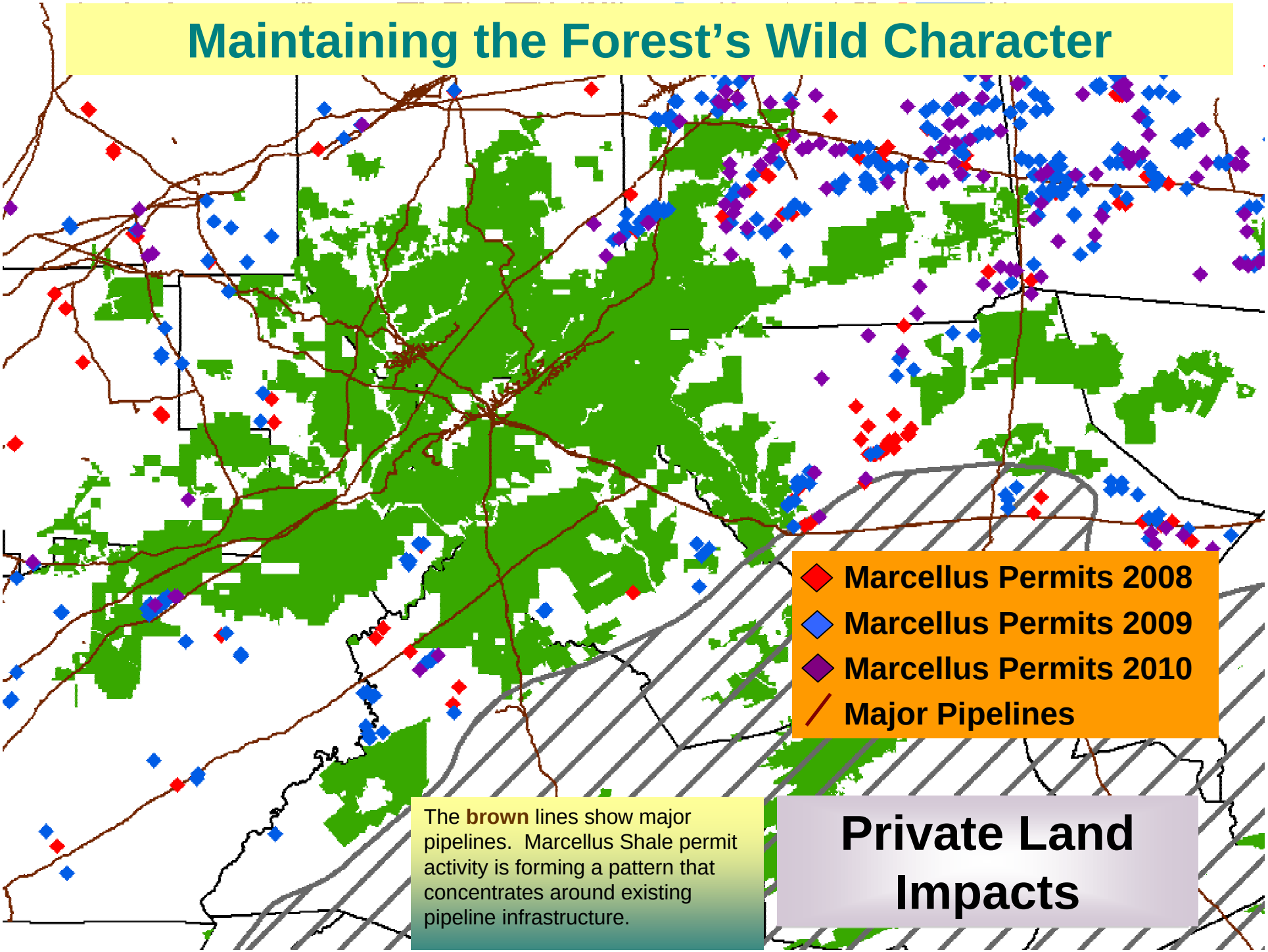
Maintaining the Forest's Wild Character



Maintaining the Forest's Wild Character



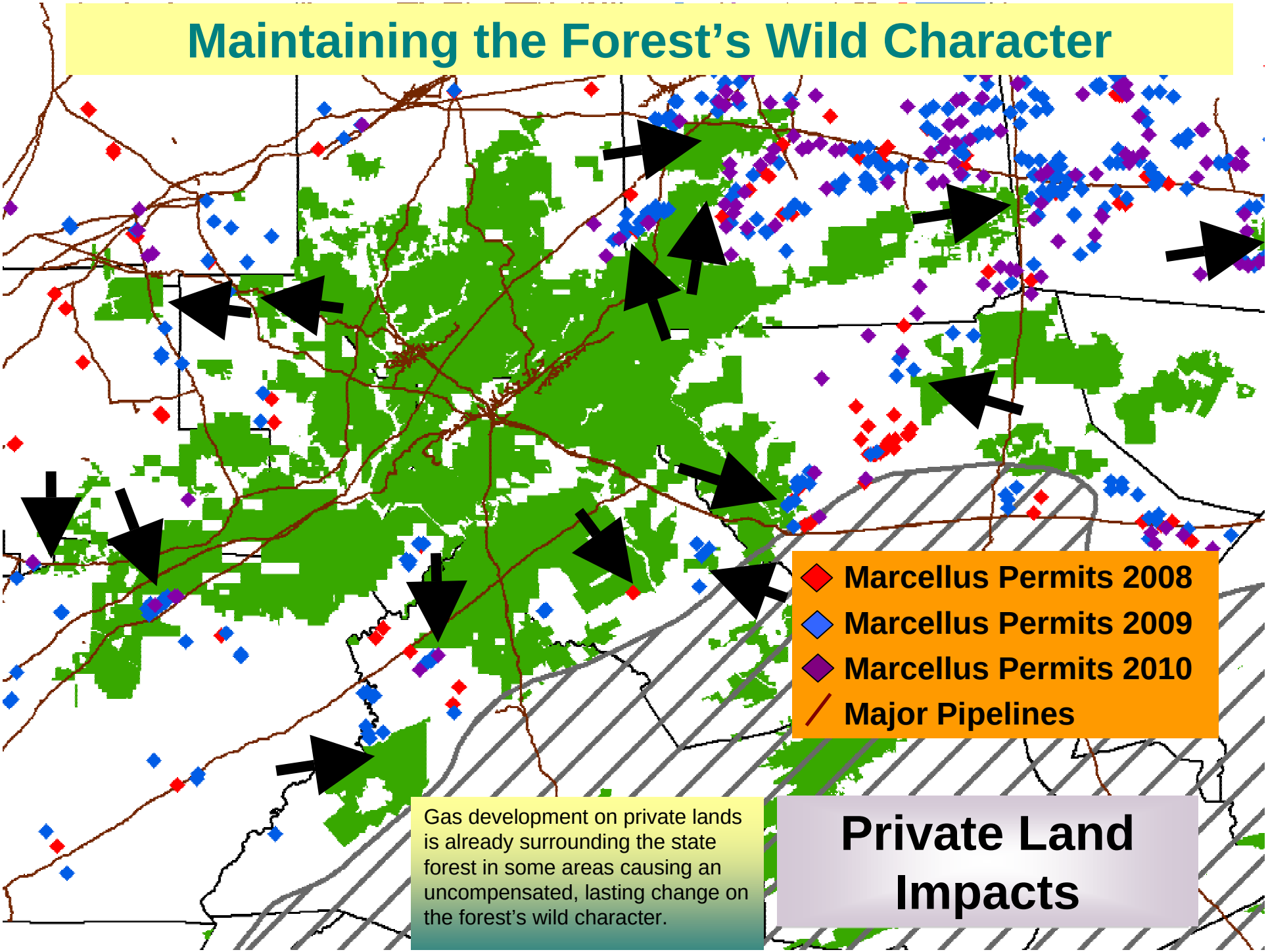
Maintaining the Forest's Wild Character



The **brown** lines show major pipelines. Marcellus Shale permit activity is forming a pattern that concentrates around existing pipeline infrastructure.

Private Land Impacts

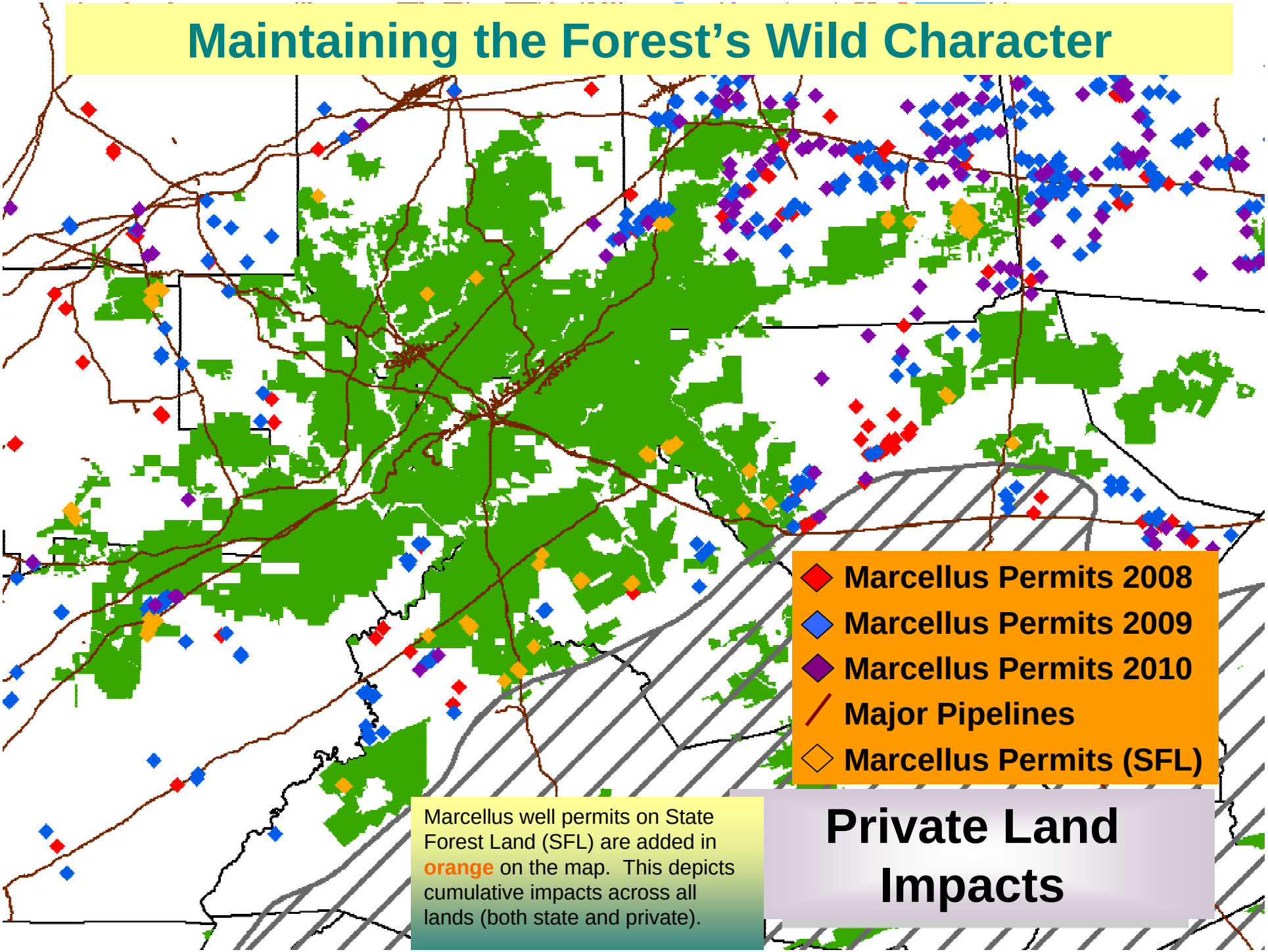
Maintaining the Forest's Wild Character



Gas development on private lands is already surrounding the state forest in some areas causing an uncompensated, lasting change on the forest's wild character.

Private Land Impacts

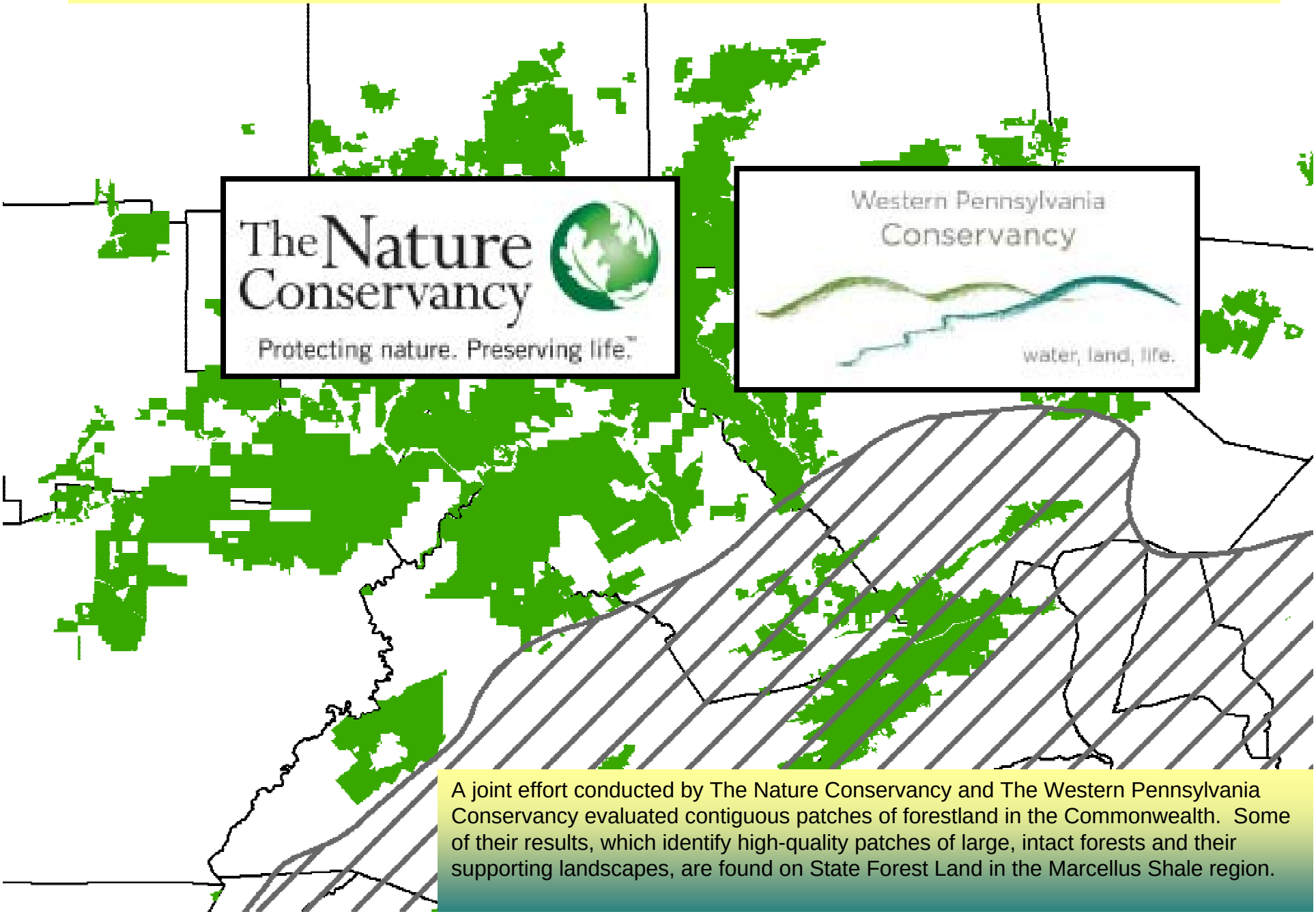
Maintaining the Forest's Wild Character



Marcellus well permits on State Forest Land (SFL) are added in **orange** on the map. This depicts cumulative impacts across all lands (both state and private).

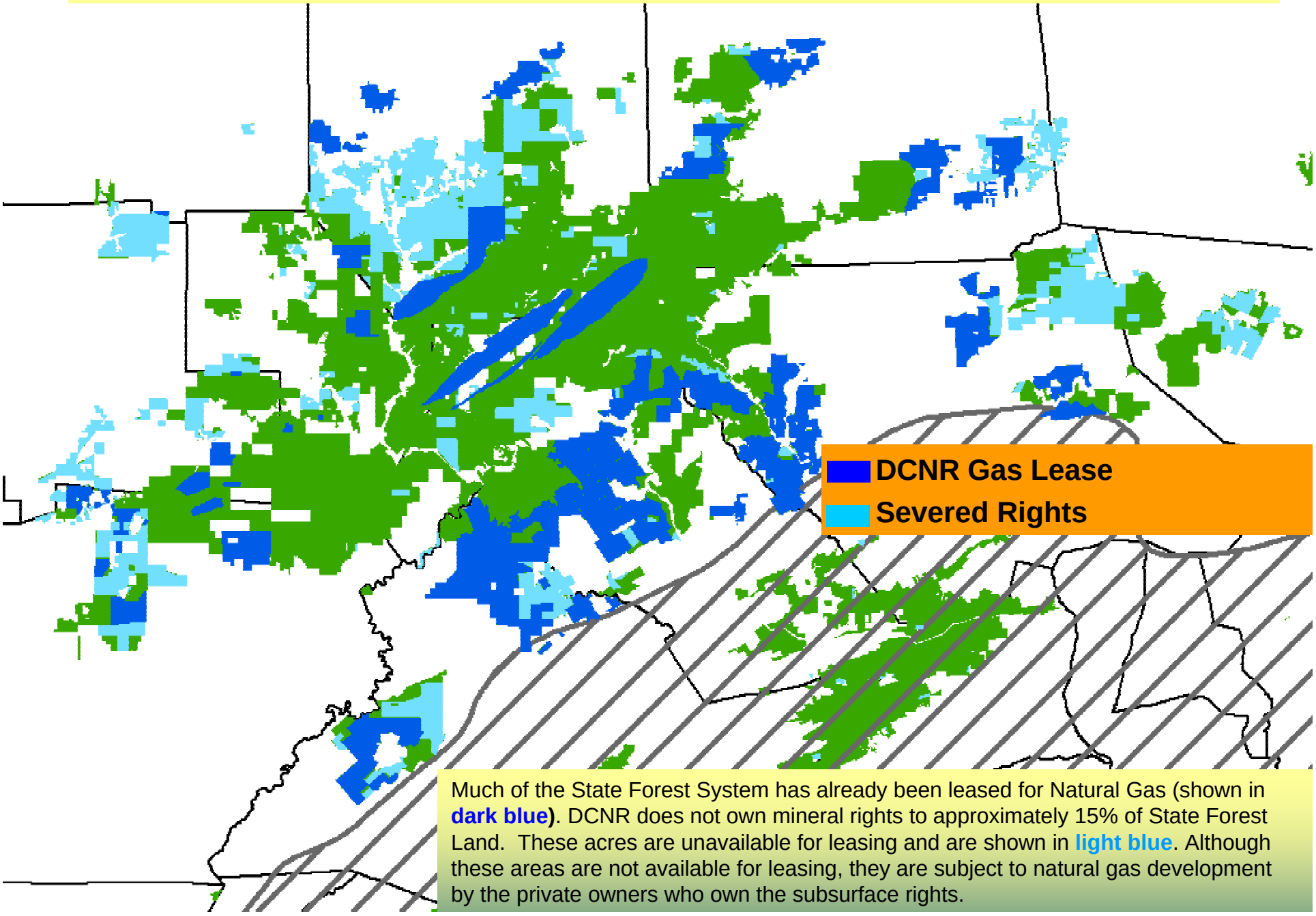
Private Land Impacts

TNC-WPC Priority Forest Patches



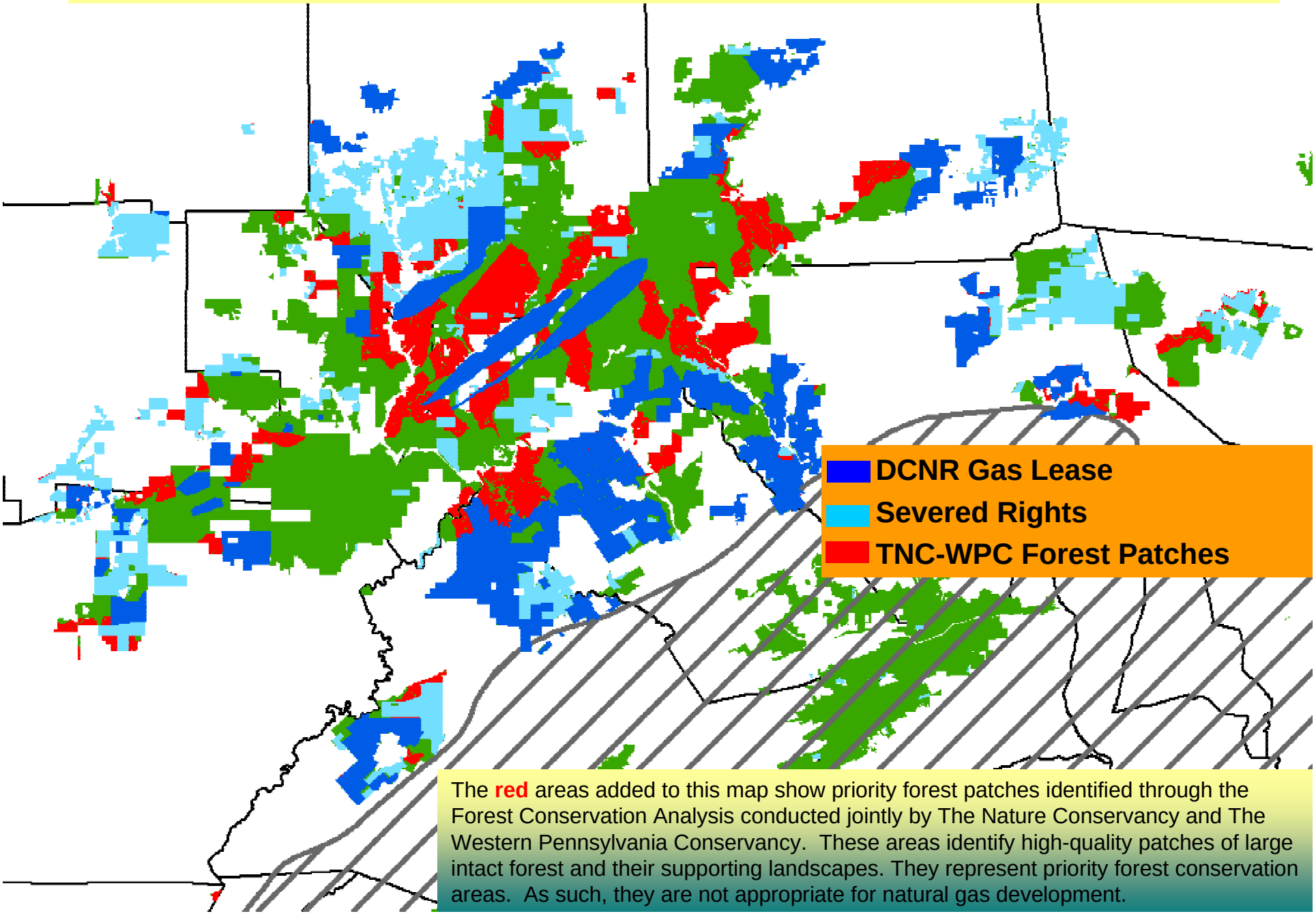
A joint effort conducted by The Nature Conservancy and The Western Pennsylvania Conservancy evaluated contiguous patches of forestland in the Commonwealth. Some of their results, which identify high-quality patches of large, intact forests and their supporting landscapes, are found on State Forest Land in the Marcellus Shale region.

TNC-WPC Priority Forest Patches



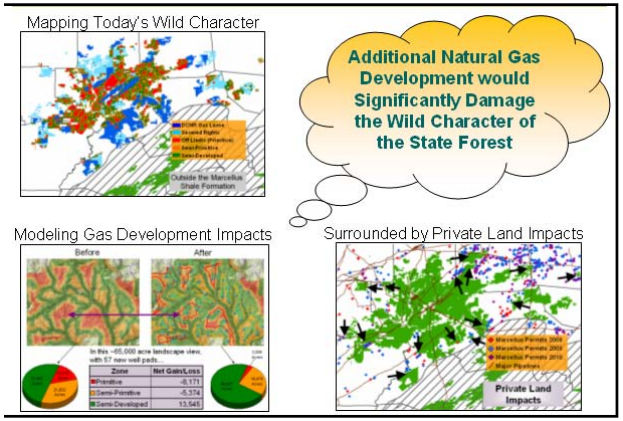
Much of the State Forest System has already been leased for Natural Gas (shown in **dark blue)**. DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

TNC-WPC Priority Forest Patches

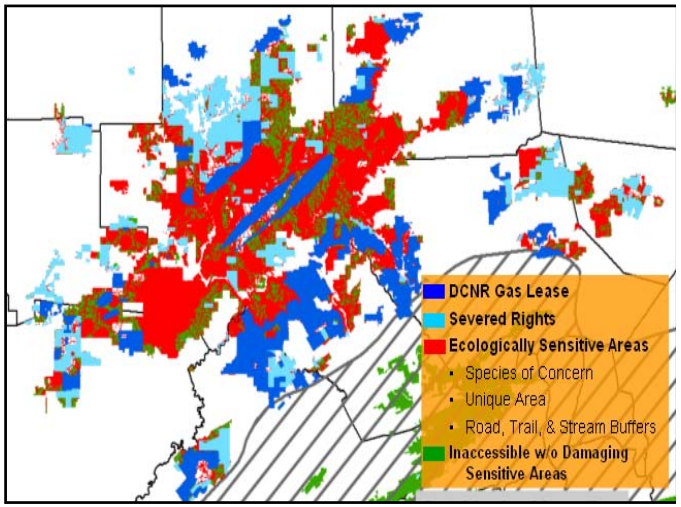


The **red** areas added to this map show priority forest patches identified through the Forest Conservation Analysis conducted jointly by The Nature Conservancy and The Western Pennsylvania Conservancy. These areas identify high-quality patches of large intact forest and their supporting landscapes. They represent priority forest conservation areas. As such, they are not appropriate for natural gas development.

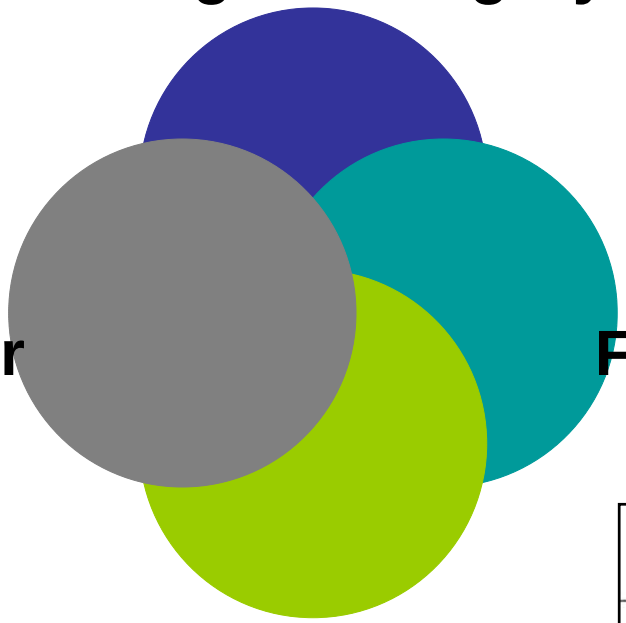
Cumulative Assessment & Impacts



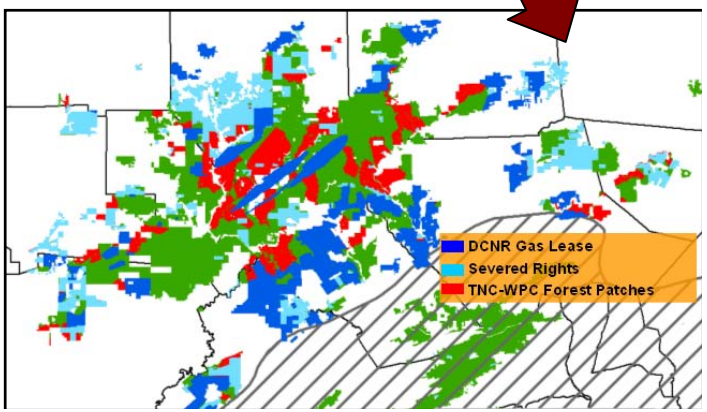
The Forest's Ecological Integrity



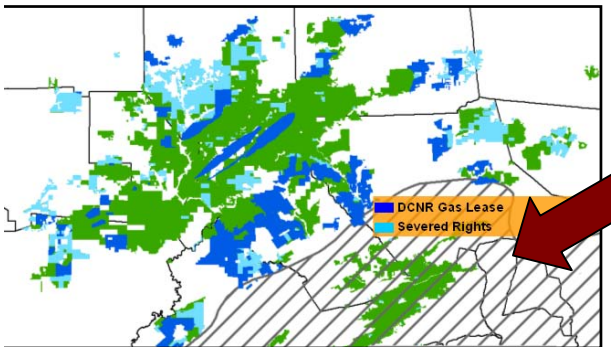
The Forest's Wild Character



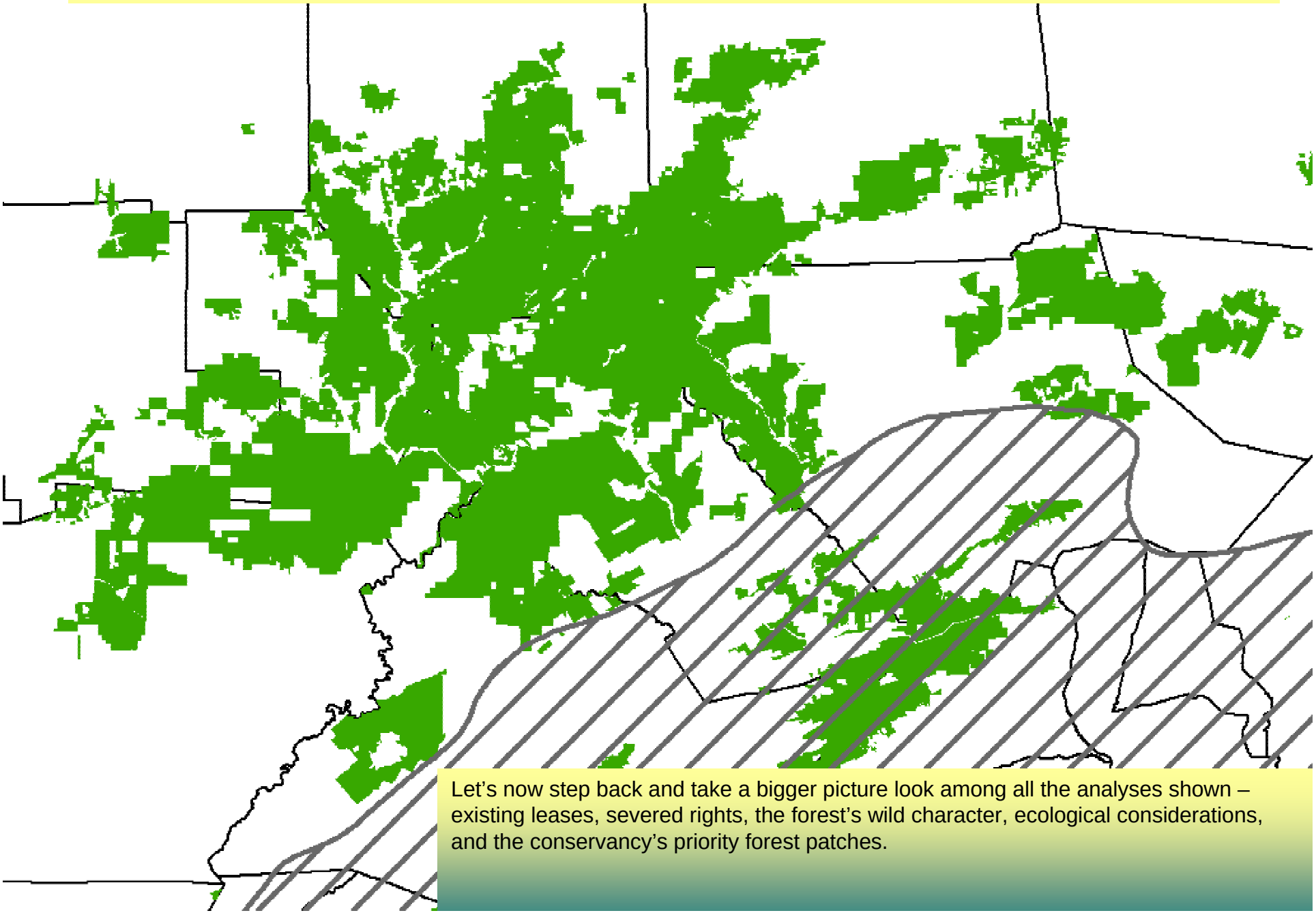
TNC-WPC Forest Patches



Existing Leases & Severed Rights

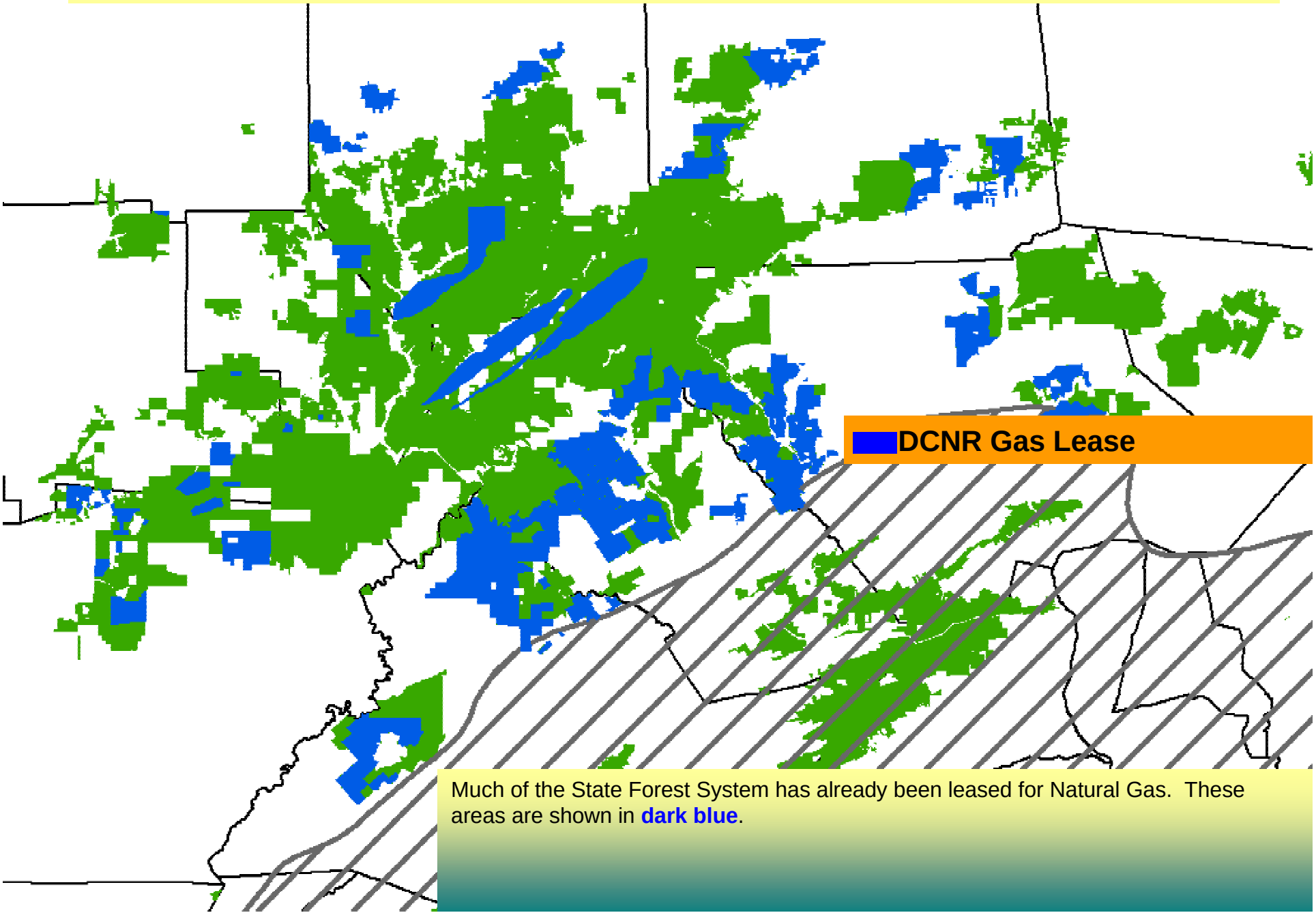


Cumulative Assessment & Impacts



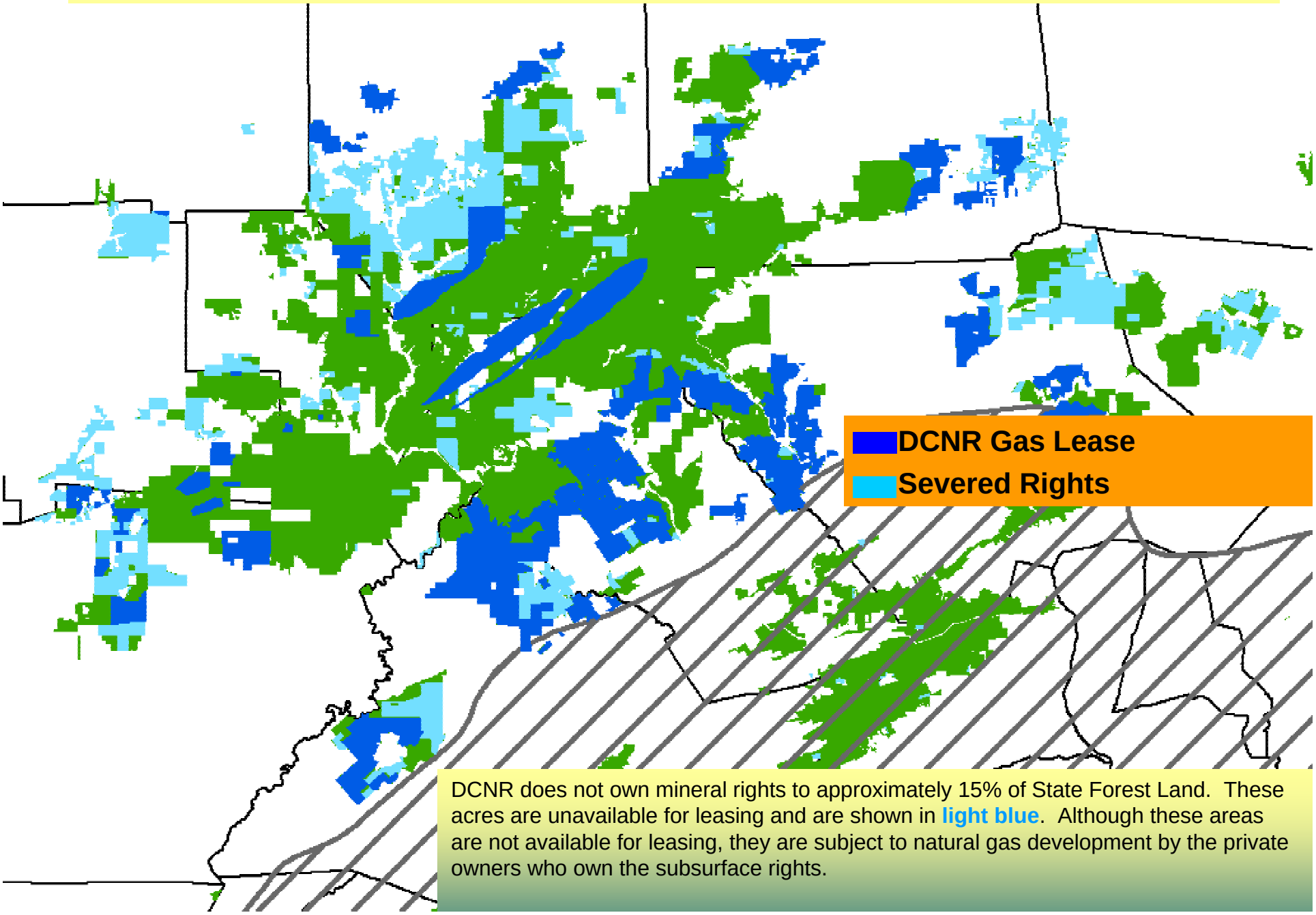
Let's now step back and take a bigger picture look among all the analyses shown – existing leases, severed rights, the forest's wild character, ecological considerations, and the conservancy's priority forest patches.

Cumulative Assessment & Impacts



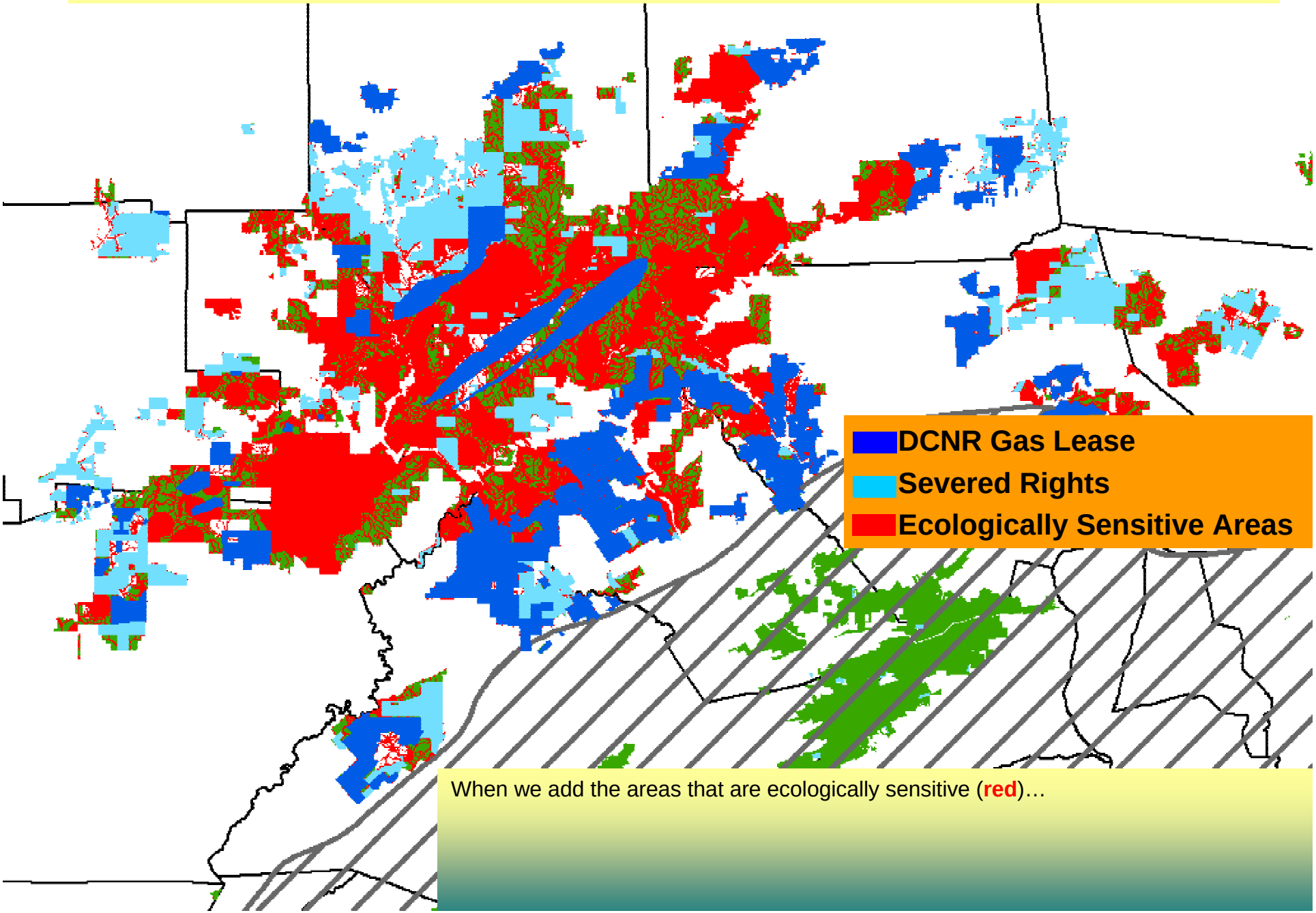
Much of the State Forest System has already been leased for Natural Gas. These areas are shown in **dark blue**.

Cumulative Assessment & Impacts



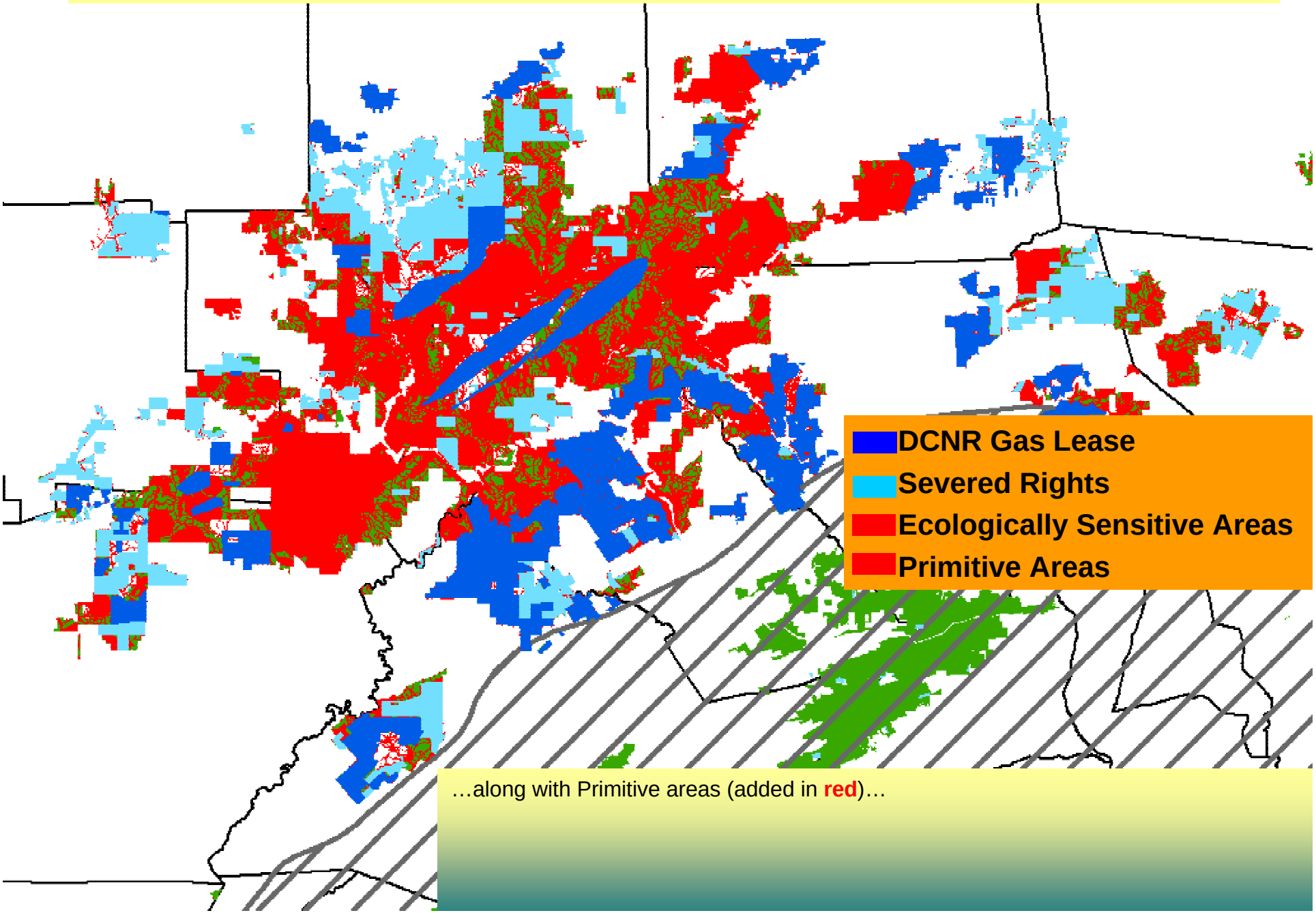
DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Cumulative Assessment & Impacts



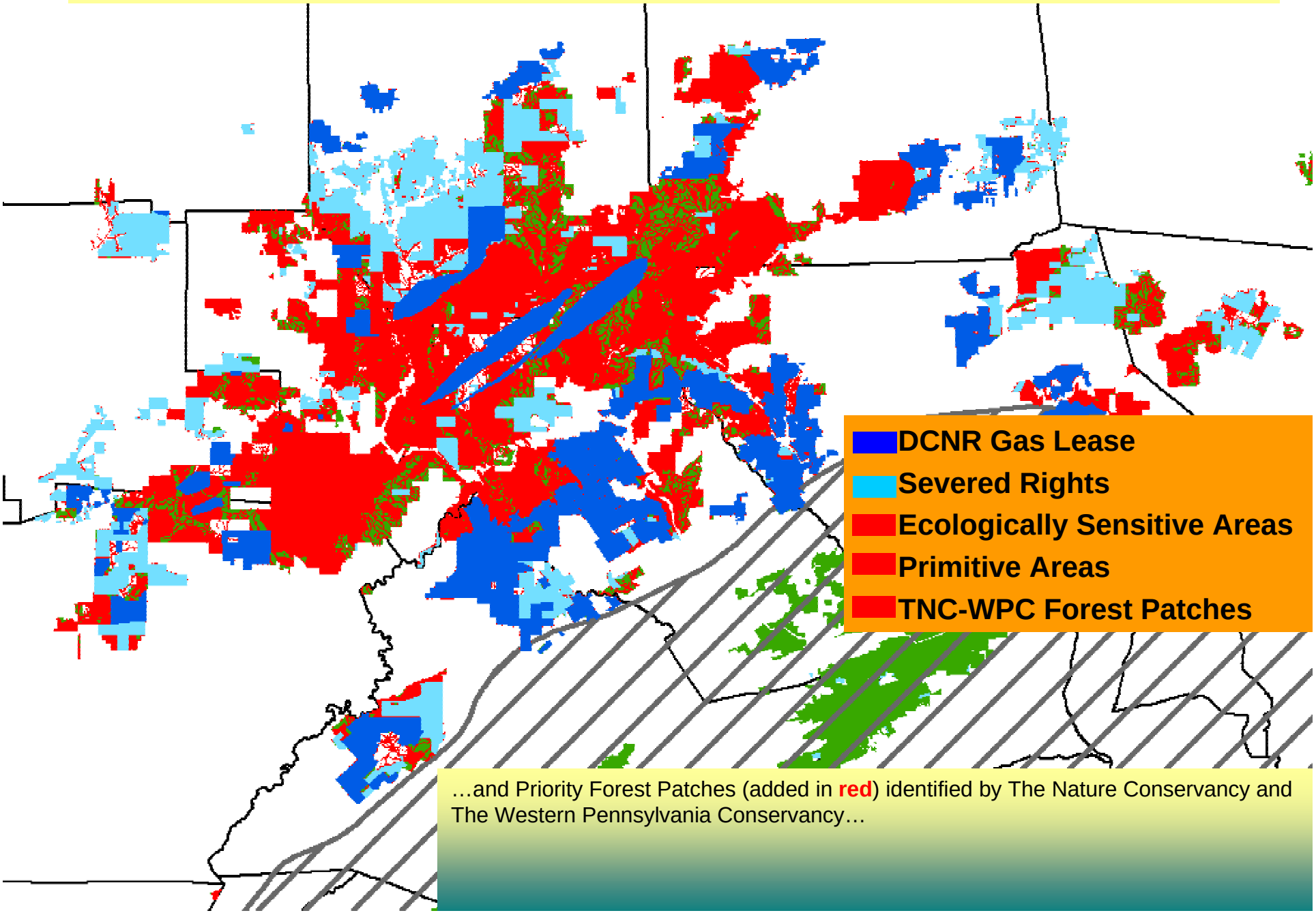
When we add the areas that are ecologically sensitive (**red**)…

Cumulative Assessment & Impacts



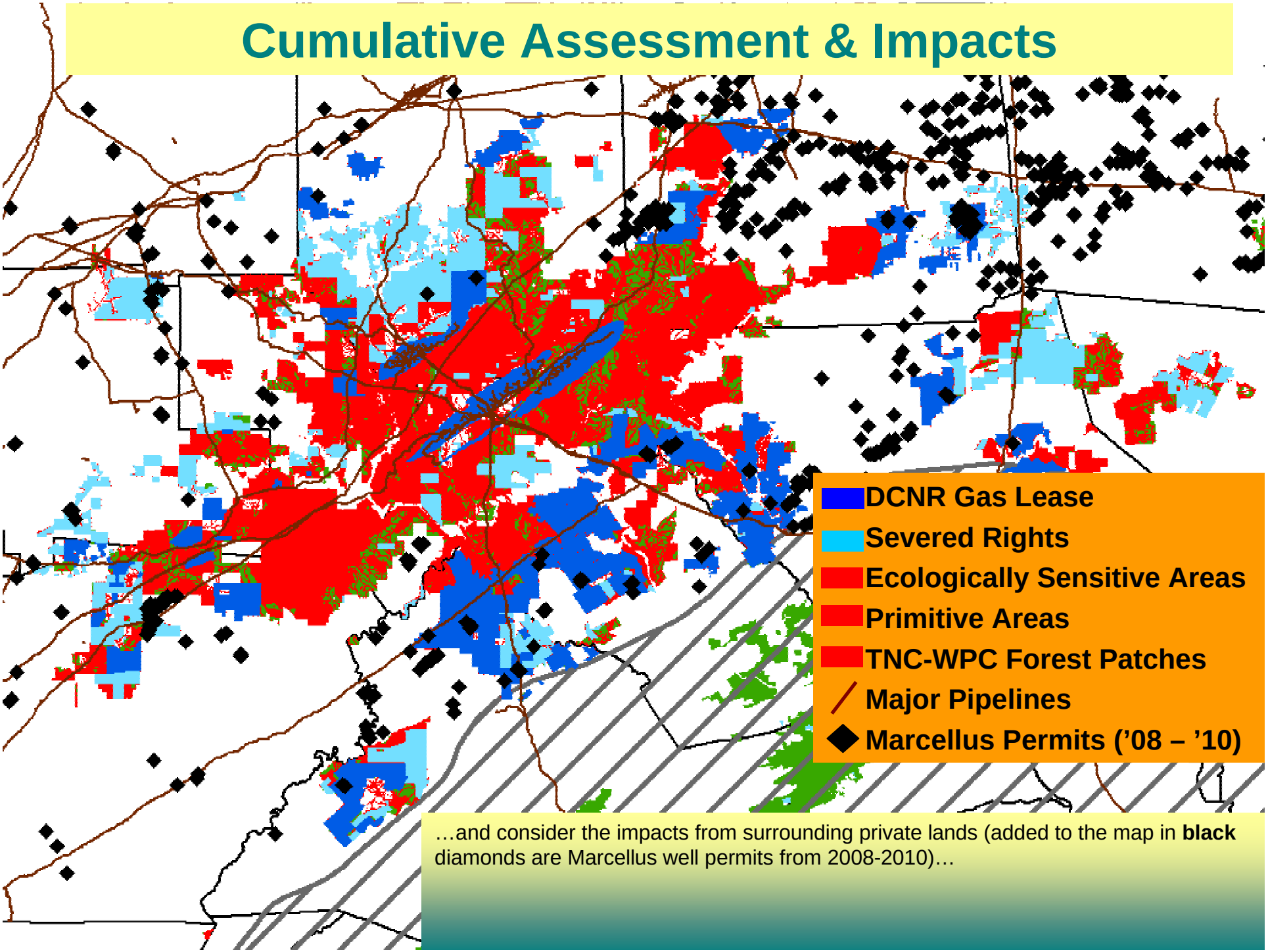
…along with Primitive areas (added in **red**)…

Cumulative Assessment & Impacts



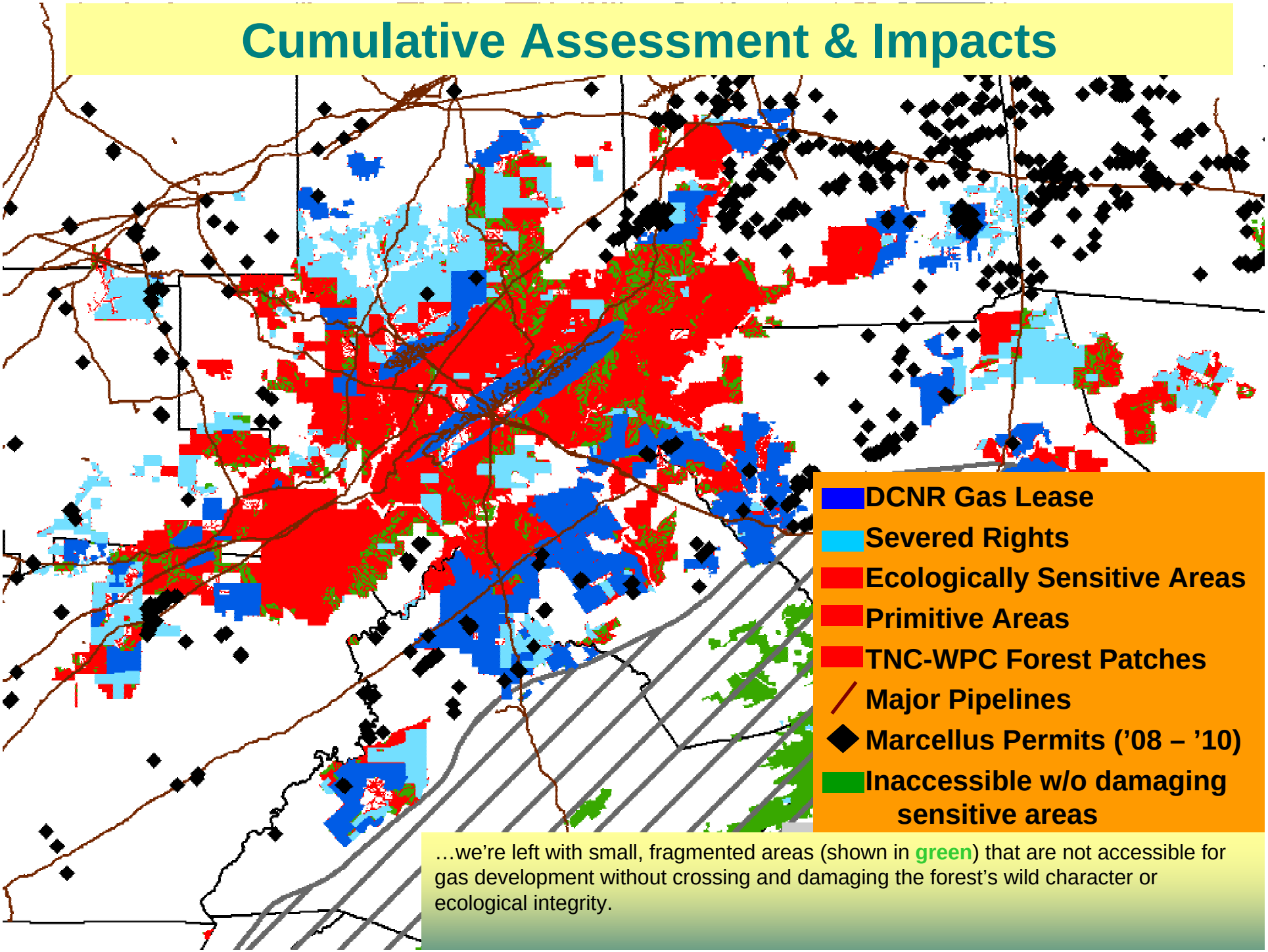
…and Priority Forest Patches (added in **red**) identified by The Nature Conservancy and The Western Pennsylvania Conservancy…

Cumulative Assessment & Impacts



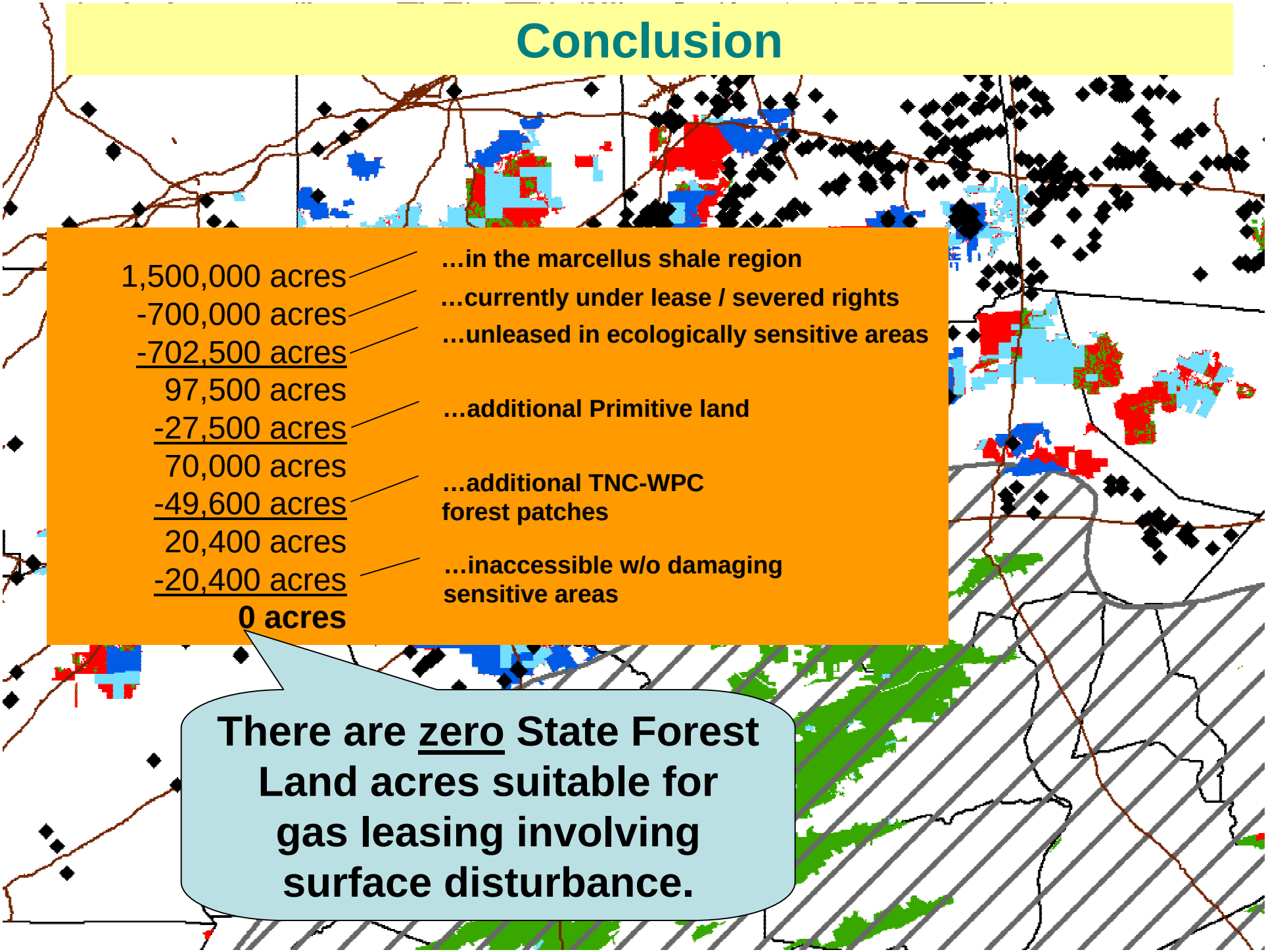
…and consider the impacts from surrounding private lands (added to the map in **black** diamonds are Marcellus well permits from 2008-2010)…

Cumulative Assessment & Impacts



…we're left with small, fragmented areas (shown in **green**) that are not accessible for gas development without crossing and damaging the forest's wild character or ecological integrity.

Conclusion



1,500,000 acres	**…in the marcellus shale region**
-700,000 acres	**…currently under lease / severed rights**
-702,500 acres	**…unleased in ecologically sensitive areas**
97,500 acres	
-27,500 acres	**…additional Primitive land**
70,000 acres	
-49,600 acres	**…additional TNC-WPC forest patches**
20,400 acres	
-20,400 acres	**…inaccessible w/o damaging sensitive areas**
0 acres	

There are zero State Forest Land acres suitable for gas leasing involving surface disturbance.

Ohio Announces Tougher Permit Conditions for Drilling Activities Near Faults and Areas of Seismic Activity

4/11/2014 *Ohio DNR* *in Oil and Gas*

COLUMBUS, OH – Today Ohio Department of Natural Resources (ODNR) Director James Zehringer announced new, stronger permit conditions for drilling near faults or areas of past seismic activity. The new policies are in response to recent seismic events in Poland Township (Mahoning County) that show a probable connection to hydraulic fracturing near a previously unknown microfault.

New permits issued by ODNR for horizontal drilling within 3 miles of a known fault or area of seismic activity greater than a 2.0 magnitude would require companies to install sensitive seismic monitors. If those monitors detect a seismic event in excess of 1.0 magnitude, activities would pause while the cause is investigated. If the investigation reveals a probable connection to the hydraulic fracturing process, all well completion operations will be suspended. ODNR will develop new criteria and permit conditions for new applications in light of this change in policy. The department will also review previously issued permits that have not been drilled.

“While we can never be 100 percent sure that drilling activities are connected to a seismic event, caution dictates that we take these new steps to protect human health, safety and the environment,” said Zehringer. “Not only will this reasonable course of action help to ensure public health and safety but it will also help us to expand our underground maps and provide more information about all types of seismicity in Ohio.”

“ODNR’s directives are a sensible response to a serious issue that regulators across the country are closely examining,” said Gerry Baker, Associate Executive Director of the Interstate Oil and Gas Compact Commission. “IOGCC is pleased to work with Ohio and other states to share scientific data to better understand the nature of these occurrences.”

“These additional standards add even more strength to Ohio’s already comprehensive regulatory program,” said Mike Paque, Executive Director of the Groundwater Protection Council. “State regulators are taking an aggressive lead in tackling tough and complicated oil and gas issues and ODNR is no exception.”

More than 800 wells have been drilled in Ohio’s Utica and Marcellus shale play, including as many as 16,000 hydraulic fracturing stages from those wells. Regarding the seismic events in Poland Township, Mahoning County, ODNR geologists believe the sand and water injected into the well during the hydraulic fracturing process may have increased pressure on an unknown microfault in the area. Further hydraulic fracturing at the site is suspended but the company will be permitted to recover resources from five of the previously drilled wells located on the pad. This is also expected to have the beneficial effect of reducing underground pressure and decreasing the likelihood of another seismic event.

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Under ODNR's lead, Ohio has joined a consortium of state regulators dedicated to learning more about seismic activity, especially as it relates to oil and gas activity. The members of this consortium are currently working with the Interstate Oil and Gas Compact Commission and Groundwater Protection Council to share information and knowledge. The working group also hopes to draw upon current and future research to develop common procedures for how to monitor for seismic activity and respond if activity occurs.

The Ohio Seismic Network, coordinated by ODNR and operated by various partners, began recording seismic events in 1999. Before that time, the recording of seismic events varied from distant machines and felt reports. Ohio has a history of seismic activity, and since the network has established, Ohio has experienced 109 events greater than 2.0 magnitude. Data from the Ohio Seismic Network will be used as part of our new application review process.

A map of underground seismic faults and past seismic events is available at oilandgas.ohiodnr.gov.

ODNR ensures a balance between wise use and protection of our natural resources for the benefit of all. Visit the ODNR website at ohiodnr.gov.

Tags: Oil and Gas

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Potentially induced earthquakes in Oklahoma, USA: Links between wastewater injection and the 2011 M_w 5.7 earthquake sequence

Katie M. Keranen[1], Heather M. Savage[2], Geoffrey A. Abers[2], and Elizabeth S. Cochran[3]
[1]ConocoPhillips School of Geology and Geophysics, University of Oklahoma, 100 E. Boyd Street, Norman, Oklahoma 73069, USA
[2]Lamont-Doherty Earth Observatory of Columbia University, PO Box 1000, 61 Route 9W, Palisades, New York 10964, USA
[3]U.S. Geological Survey, 525 S. Wilson Avenue, Pasadena, California 91106, USA

ABSTRACT

Significant earthquakes are increasingly occurring within the continental interior of the United States, including five of moment magnitude (M_w) ≥ 5.0 in 2011 alone. Concurrently, the volume of fluid injected into the subsurface related to the production of unconventional resources continues to rise. Here we identify the largest earthquake potentially related to injection, an M_w 5.7 earthquake in November 2011 in Oklahoma. The earthquake was felt in at least 17 states and caused damage in the epicentral region. It occurred in a sequence, with 2 earthquakes of M_w 5.0 and a prolific sequence of aftershocks. We use the aftershocks to illuminate the faults that ruptured in the sequence, and show that the tip of the initial rupture plane is within ~200 m of active injection wells and within ~1 km of the surface; 30% of early aftershocks occur within the sedimentary section. Subsurface data indicate that fluid was injected into effectively sealed compartments, and we interpret that a net fluid volume increase after 18 yr of injection lowered effective stress on reservoir-bounding faults. Significantly, this case indicates that decades-long lags between the commencement of fluid injection and the onset of induced earthquakes are possible, and modifies our common criteria for fluid-induced events. The progressive rupture of three fault planes in this sequence suggests that stress changes from the initial rupture triggered the successive earthquakes, including one larger than the first.

INTRODUCTION

Three earthquakes with M_w of 5.0, 5.7, and 5.0 (moment magnitudes from Global Centroid Moment Tensor Catalog, GCMT; http://www.globalcmt.org) occurred within the North American midcontinent near Prague, Oklahoma, United States (Fig. 1) on 5, 6, and 8 November 2011 ~180 km from the nearest known Quaternary-active fault. Earthquakes with $M_w \geq 5.0$ are rare in the United States east of the Rocky Mountains; however, the number per year recorded in the midcontinent increased 11-fold between 2008 and 2011, compared to 1976–2007. Of the total seismic moment released in the region, ~66% occurred in 2011 (from the GCMT). The M_w 5.7 earthquake was the largest instrumentally recorded in Oklahoma. It created shaking up to intensity VIII in the epicentral region, destroyed 14 homes, damaged many other buildings, injured 2 people, and buckled pavement (U.S. Geological Survey, 2011). In this study we refer to the $M_w \geq 5.0$ earthquakes of 5, 6, and 8 November 2011 as events A, B, and C, respectively. Moment tensor solutions (from the GCMT;

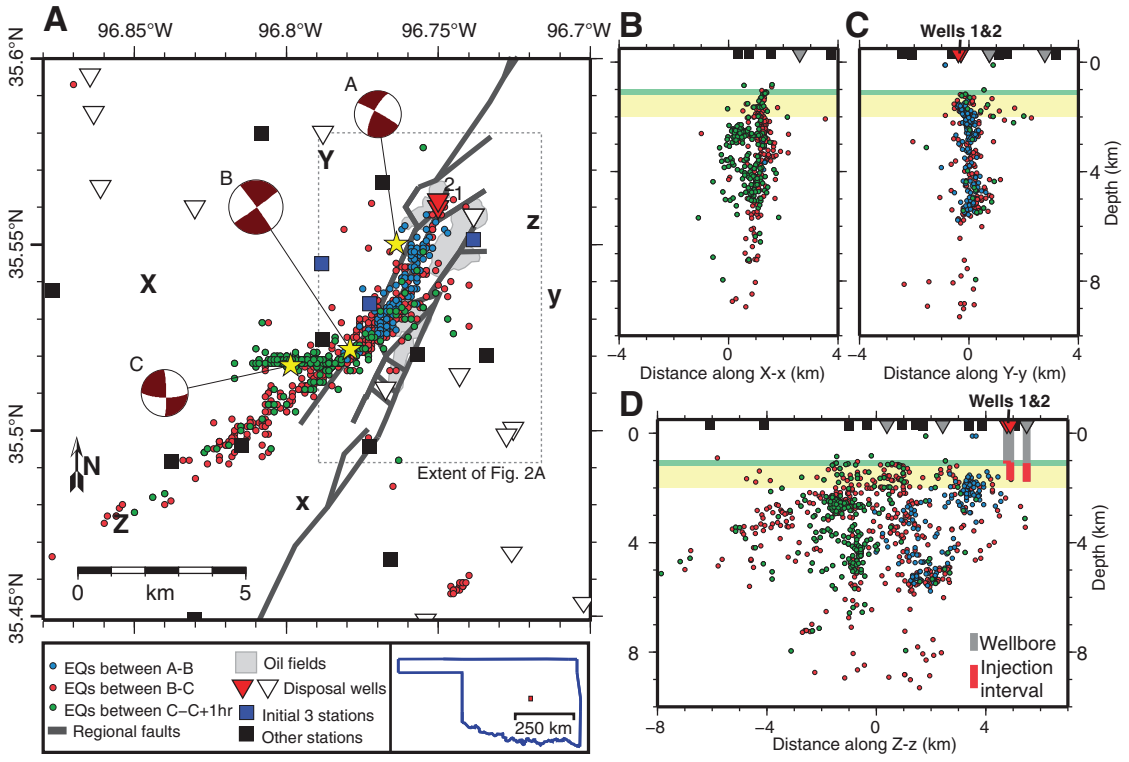


Figure 1. A: Seismicity, centroid moment tensor mechanisms, seismic stations, active disposal wells, and oil fields in central Oklahoma, United States. Epicenters of major earthquakes (EQs) are plotted at Oklahoma Geological Survey location for event A and at our relocations for events B and C, where we had sufficient control (Table DR1 [see footnote 1]). Event A likely nucleated on fault defined by aftershock locations (permitted within location error). Faults are merged from regional compilation (Joseph, 1987) and detailed local study (Way, 1983), mapped using seismic lines, well logs, and formation tops. Wells 1 and 2 inject near aftershocks of event A. B–D: Cross sections of seismicity projected from within 4 km of plane of each section. Vertical lines beneath wells indicate well path, red where perforated or open hole. Green bands denote Hunton and Simpson Groups, and yellow bands denote Arbuckle Group. Arbuckle Group overlies basement; base depth of Arbuckle Group locally is uncertain (between 1.8 and 2.2 km depth). Depths are relative to sea level, land elevation is ~300 m. Inset shows state of Oklahoma and location of map area.

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Fig. 1; Table DR1 in the GSA Data Repository[1]) indicate strike-slip rupture on steeply dipping fault planes with different fault-plane orientations. Local earthquake activity began in February 2010 with an M_w 4.1 earthquake within a few kilometers of event A.

The 2010 and 2011 Prague earthquakes occurred in the structurally controlled Wilzetta oil field, within the complex, ~200-km-long, Pennsylvanian-age Wilzetta fault system (Way, 1983). Structural traps in the Wilzetta field are formed by the offset of porous limestone along high-angle faults (Fig. 2). Production of oil from the Wilzetta North field, where the earthquake sequence initiated, occurred primarily in the 1950s and 1960s from the Hunton Limestone; limited production continues. There are three active fluid injection wells located within 1.5 km of aftershocks of event A, and two within the Wilzetta North field (Fig. 1). Fluid injection in these wells began after 1993 and occurs into units from the Hunton Limestone to the deeper Arbuckle Group, predominantly dolomitic limestone, between ~1.3 and 2.1 km depth (Oklahoma Corporation Commission Well Data System: http://www.occpermit.com/WellBrowse; Fig. 2).

Earthquakes are commonly considered induced by wastewater disposal if they adhere to criteria established by Davis and Frohlich (1993) that include proximity to injection wells, a change from background seismicity, and a correlation with wastewater injection parameters. In this study we demonstrate a relationship between the 2011 Oklahoma seismicity and fluid injection, and suggest modifications to the criteria for induced earthquakes. We use the term "induced" without implying a relationship between anthropogenic stresses and earthquake magnitude, following the Committee on Induced Seismicity Potential (National Research Council of the National Academies, 2012).

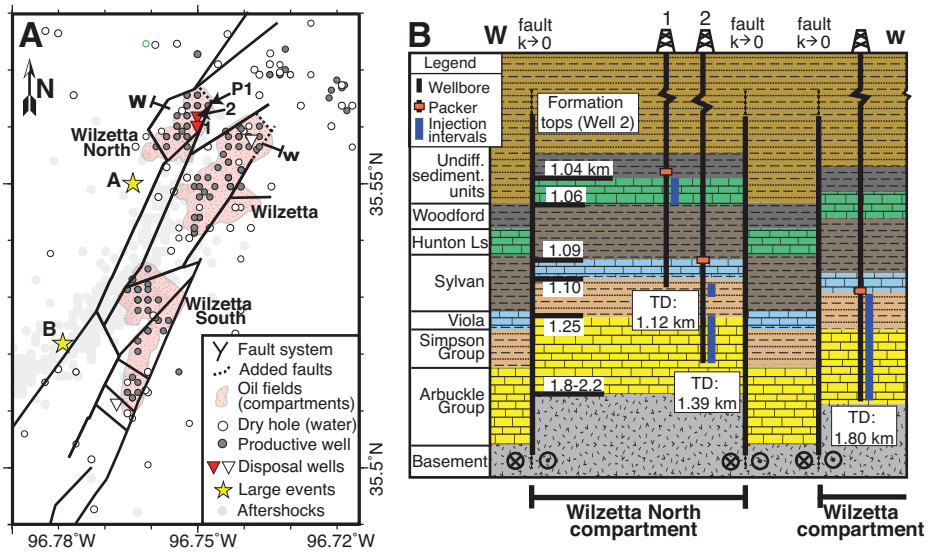


Figure 2. Subsurface geology and compartmentalization in Wilzetta oilfields, Oklahoma, United States. A: Wilzetta fault system (area shown in Fig. 1) including fault-bounded compartments, disposal wells, earthquakes, and exploration wells into Hunton Limestone or deeper units. Boundaries between producing and dry wells closely correlate to mapped faults. Wells 1, 2, and P1 are discussed in text. B: Schematic cross-section W-w across Wilzetta North and Wilzetta compartments. High-permeability reservoirs are interbedded with low-permeability shale units vertically, and faults are low-permeability barriers to fluid flow. Well paths and injection intervals are from Oklahoma Corporation Commission Well Data System (http://www.occpermit.com/WellBrowse) database. Relative offset of fault blocks is based on formation tops at closely spaced production wells (not shown). Depths to formation tops and total depth (TD) of each injection well are noted (in km below sea level).

METHODOLOGY

Seismic Data and Network

We deployed seismometers within 24 h of event A, and recorded the later 2 large earthquakes and thousands of aftershocks. The first 3 seismometers deployed, within 2 km of events A and B, recorded 7 h of locatable seismicity prior to event B. Additional seismometers (3) were deployed in the 24 h after event B, and 12 in the following 5 days, using digital three-component seismometers from the University of Oklahoma and the PASSCAL RAMP (Program for Array Seismic Studies of the Continental Lithosphere, Rapid Array Mobilization Program) pool. The locally recorded data were supplemented by EarthScope Transportable Array stations (Meltzer et al., 1999) at 25–150 km distance. Many stations were within 1 focal depth of the nearest earthquakes, providing accurate depth estimates; nonlinear inversions on sample hypocenters give 95% confidence bounds of <500 m in epicenter and <800 m in depth for earthquakes recorded by 3 stations before event B, and <50–100 m in epicenter and depth for those recorded by the full 18 station local array. Most ray paths were <10 km from source to station, with <2 s between S and P wave arrivals. Several hundred aftershocks per hour occurred within the first few hours of each large earthquake.

We report results based on P and S wave arrivals for (1) all identifiable events after the array installation before event B (the M_w 5.7), (2) 1–2 h time windows immediately following events B and C, and (3) larger aftershocks within 2 mo of the mainshocks and recorded on >15 stations. In most cases, both P and S wave arrival times could be picked to a precision of 10 ms or better from the local stations. Arrivals were picked manually; the high event rate caused standard automatic detection schemes to fail.

The one-dimensional velocity model (Fig. DR1 in the Data Repository) was determined by inversion methods that solve jointly for P and S wave velocities and hypocenters (Abers and Roecker, 1991) for aftershocks recorded on >15 stations. The global root mean square residual in the velocity model is 0.029 s, and influences of possible lateral variations appear to be minimal. (For details of the network, the velocity model, and location selection, see the Data Repository.)

RESULTS

Aftershock Locations and Fault Rupture Areas

For this study we located 1183 aftershocks recorded by the dense network, and show the best located 798 (see the Data Repository). We use the extent of the aftershocks measured within a few hours to days after the mainshocks to estimate the area of the faults that ruptured, as is common if an event does not rupture to the surface (e.g., Kanamori and Anderson, 1975). The aftershocks we use in this study represent <10% of the total number of earthquakes, as only a few hours of data from time periods following each $M_w \geq 5.0$ event have been examined thoroughly. Hypocenters for events A, B, and C are less well constrained than the aftershocks (see the Data Repository). However, the fault rupture sequence is clear from the focal mechanisms of the large events combined with the aftershock pattern.

The earthquakes located delineate the major seismic zones as narrow, steeply dipping planes in the sedimentary section and basement (Fig. 1), well correlated to previously identified fault structures (Way, 1983; Joseph, 1987). The strikes (from the GCMT) of events A (27°) and B

[1]GSA Data Repository item 2013191, network and event details, velocity model, and 2010–2011 injection data, is available online at www.geosociety.org/pubs/ft2013.htm, or on request from editing@geosociety.org or Documents Secretary, GSA, P.O. Box 9140, Boulder, CO 80301, USA.

(54°) parallel the two predominant orientations within the Wilzetta fault zone, and the strike of event C (91°) defines a clear secondary orientation. Therefore, three separate segments within the Wilzetta fault network ruptured successively during the sequence. The slip on the apparent fault planes of the three largest earthquakes are consistent with an east-northeast direction of maximum horizontal stress. Significantly, the northern tip of the aftershock zone for event A is in sedimentary units near an active disposal well (Fig. 1); the closest earthquakes are 200 ± 250 m distant from the wells. The depths of 83% of the aftershocks are <5 km; 30% of early aftershocks (and 20% of all earthquakes) were located within the sedimentary units into which fluids are injected (Fig. 1).

Fluid Triggering and Correlation of Seismicity to Fluid Injection Data

Earthquake triggering by fluid injection occurs if pore pressure at the fault increases beyond a critical pressure threshold (Hubbert and Rubey, 1959; Healy et al., 1968; Raleigh et al., 1976), lowering effective normal stress on a fault close to failure. In the induced seismicity experiment at Rangely, Colorado, downhole reservoir pressure measurements were available and the seismicity rate rose and fell within months of changes in reservoir pressure (Raleigh et al., 1976). Pressure data available for the Wilzetta North field are limited to monthly reported wellhead pressure (pressure at the surface while pumping), and no direct measurements of pressure within the reservoir are accessible. We thus follow standard methods and investigate possible temporal correlations between seismicity rate and surface injection parameters (e.g., Healy et al., 1968; Frohlich et al., 2011; Horton, 2012).

No short-term monthly correlation is evident in the Wilzetta field (Fig. DR2). Such a temporal correlation to surface injection parameters is rare, though evident at the Rocky Mountain Arsenal in Colorado (Healy et al., 1968). A more common observation in cases of induced seismicity is the onset of earthquakes soon after the initiation of fluid injection. Seismicity began within months of the start date of injection at the Rocky Mountain Arsenal (Healy et al., 1968), in Arkansas (Horton, 2012), and at the Dallas–Fort Worth (Texas) airport (Frohlich et al., 2011). However, within oilfields near Prague, Oklahoma, the first noted earthquake (M_w 4.1, 2010) did not occur until 17 yr after injection commenced (Fig. 3A). It is difficult to know if small earthquakes were occurring prior to 2010 near Prague, given the lack of nearby seismic stations; none were recorded or reported. A similarly long delay was observed at the Cogdell oil field in Texas (Davis and Pennington, 1989), where induced earthquakes began 20 yr after injection initiated.

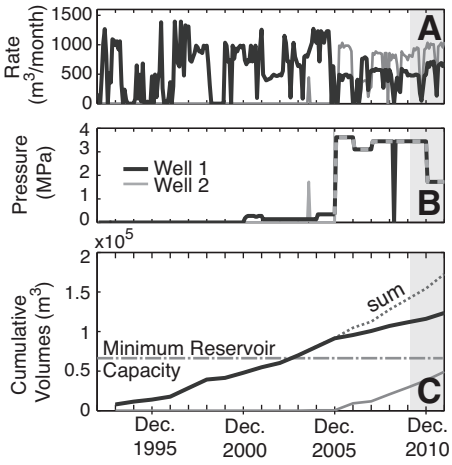


Figure 3. Available injection data. A: Monthly volumes of wastewater disposed at injection wells 1 and 2 (Fig. 2) near nucleation of event A. Monthly volumes were reported for 2002–2011; daily average volumes are multiplied by number of days per month for 1993–2002. B: Wellhead pressure for periods when pump is active, for same wells. C: Cumulative volume injected at wells 1 and 2 (from yearly totals). Minimum capacity of reservoir is denoted as horizontal dashed line and equals volume of oil extracted from Wilzetta North field, estimated by dividing total volume extracted from three Wilzetta fields by fractional area of Wilzetta North. This is absolute minimum estimate of reservoir fluid capacity; no data are available for water extracted or reinjected during production. Gray shading notes earthquakes in 2010–2011.

Increasing Injection (and Reservoir?) Pressure

Wellhead pressure in the Wilzetta North field appears fixed at a constant value during pumping, as it was at Rangely, Colorado (Gibbs et al., 1972), with multiyear intervals of constant surface pressure punctuated by step increases (Well 1; Fig. 3). Initially, fluid was injected into the Hunton Limestone in Well 1 at zero reported wellhead pressure (Oklahoma Corporation Commission Well Data System) (Fig. 3B), signifying an underpressured reservoir (below hydrostatic pressure) depleted by earlier hydrocarbon production. Wellhead pressure increased in steps, starting in 2001 at ~0.2 MPa (25–40 psi) and reaching a maximum of 3.6 MPa (525 psi) in 2006 (Fig. 3). The final tenfold increase in wellhead pressure, and the concurrent addition of a second disposal well into deeper units, came after the volume of water injected into the Hunton Limestone at Well 1 exceeded the volume of oil extracted from the Hunton strata at wells throughout the compartment (Way, 1983) (Fig. 3C). The volume of oil extracted is only an approximate estimate of reservoir capacity, and likely an underestimate; no data are available for water volume extracted or reinjected during production.

In the Wilzetta field, hydrocarbon accumulations were isolated to fault blocks of <1 km^2 areal extent, surrounded by water-saturated zones, indicating that the compartment-bounding faults were likely seals against fluid migration over geologic time. Such low-permeability barriers are common in sedimentary basins (Bradley and Powley, 1994) and can inhibit the diffusion of fluid pressure. In an idealized sealed reservoir, reservoir pressure gradually rises as injection volume increases (Fig. 4A), and the pressure difference between wellhead pressure (corrected for the water column) and reservoir pressure decreases (Fig. 4B), along with flow rate. When wellhead pressure is increased, as in the Wilzetta North field (Fig. 3), pressure gradient and flow rate increase. With sufficient time, volume injected, and wellhead pressure, pressure at the fault may exceed the critical pressure (Fig. 4B) and trigger slip. The time required for pressure at the fault to rise to the critical threshold in a closed compartment depends upon injection rate and reservoir volume and permeability, explaining delays before the onset of induced seismicity such as observed in this study and at the Cogdell oil field (Davis and Pennington, 1989).

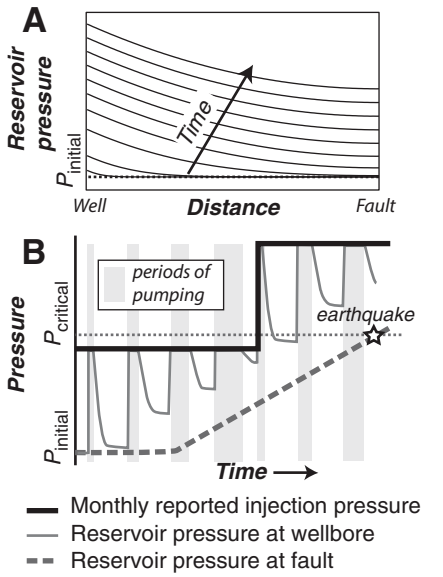


Figure 4. A: Reservoir pressure in simplistic sealed reservoir. Fluid pressure in reservoir, including at fault, rises through time as reservoir fills. Left edge of model is injection wellbore; right edge represents sealed fault. B: Predicted reservoir pressure compared to reported monthly wellhead pressure (plus weight of water column), apparently constant because pressure is reported only during pumping. Reservoir pressure near wellbore equals reported injection pressure while pumping, but drops when pump stops. Over multiple pumping cycles, time-averaged formation pressure near well rises slowly (A), and pressure gradient decreases, lowering flow rate and requiring longer periods of pumping (shaded in gray) to maintain constant monthly disposal volume. When wellhead pressure is increased, pressure gradient increases and pumping becomes more efficient.

Neither reservoir pressure data nor detailed flow rates, required to fully test this hypothesis, are available for the Prague, Oklahoma, wells. Injection rate in Oklahoma is reported as a monthly volume and the averaging of flow rate per month smooths out higher frequency variations. Alternative hypotheses to raise fluid pressure at the fault unrelated to the identified compartments, including the concurrent increase in wellhead pressure and the addition of a second injection well in 2006, cannot be rejected without reservoir pressure data. However, the agreement between original oil volume extracted and cumulative water injected prior to seismicity (Fig. 3) supports the notion that a critical volume was reached through injection in the Wilzetta North compartment.

Minor production is reported from the Hunton Limestone 500 m to the north, near the edge of the compartment (Fig. 2; well P1) (Oklahoma Corporation Commission Well Data System). It is unknown if the well is in pressure communication with the injection wells, because we have no measurements of reservoir pressure to determine connectivity. However, fluid pressure can rise throughout portions of a semirestricted reservoir following injection, and high fluid pressure can be maintained for years even if one side is infinitely open, as observed at the Rocky Mountain Arsenal (Hsieh and Bredehoeft, 1981).

DISCUSSION

Continuing injection over 18 yr into subsurface compartments in the Wilzetta field may have refilled a compartment, eventually reducing the effective stress along reservoir-bounding faults and triggering the 2010–2011 earthquakes. Injection has continued and earthquakes with magnitudes ≥3.0 continue to occur. We interpret event A (M_w 5.0) to have been induced by increased fluid pressure, exceeding the largest earthquake known to be induced by injected fluid (M_w 4.8; National Research Council of the National Academies, 2012). Aftershocks of event A appear to deepen away from the well, and may imply downward pressure propagation into basement. Event B, of much larger magnitude (M_w 5.7), and event C may also be considered consequences of injection; however, Coulomb stress calculations show that the fault geometries are consistent with triggering by stress transfer (Cochran et al., 2012). The triggering implies that the faults were close to failure, supporting the view that favorably oriented faults are critically stressed throughout the continents (Zoback et al., 2002). In this manner, small- to moderate-sized injection-induced events may result in release of additional tectonic stress. The scalar moment released in the Oklahoma sequence exceeds predictions based on the volume of injected fluid (McGarr, 1976) by several orders of magnitude, requiring the release of substantial tectonic stress.

The 2011 Prague, Oklahoma, earthquakes necessitate reconsideration of the maximum possible size of injection-induced earthquakes, and of the time scale considered diagnostic of induced seismicity. Typically, a response of seismicity to injection within months has been sought to diagnose earthquake triggering (Raleigh et al., 1976; Davis and Frohlich, 1993). Here we present a potential case of fluid injection into isolated pockets resulting in seismicity delayed by nearly 20 yr from the initiation of injection, and by 5 yr following the most substantial increase in wellhead pressure.

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Appendix C

Review of NYSERDA Commissioned Review of Myers Comments on the 2009 DSGEIS

Prepared by: Tom Myers

11/30/11

Introduction

The New York State Energy and Resource Development Agency (NYSERDA) commission Alpha Geosciences (Alpha) to complete a review of the comments I had prepared for the 2009 Draft Supplemental Generic Environmental Impact State (DSGEIS). This report replies to some of those review comments. Throughout, I refer to the review as "Alpha".

General Points

Alpha divided my comments into various subsets for their response, but they rely very much on several points throughout their response. One is their perception of there being no hydraulic connection between groundwater at depth, in the Marcellus shale, and the near-surface aquifers; they also dismiss the analysis from ICF (2009) on the same basis, even though they have no data with which to dismiss the argument. Their second line of reasoning is the results or conclusions from the 2004 EPA study of coal bed methane fracking.

Alpha rejects the suggestion that a water balance for the project area or subareas "would not serve the purpose of the SGEIS" (Alpha, at 4). They provide no reason for this conclusion, but also state that a "water balance clearly is site-specific" (Id.). A water balance can be useful for any size study area or portion of the study area. A water balance for the overall study area would help to understand the total volume of water involved in fracking; a similar argument can be made for a watershed – a water balance for the groundwater would help to understand whether the water amounts used for fracking is a substantial portion of the local water balance.

Alpha partially rejects my suggestion that a better description of the area's hydrogeology is needed by quoting my statement that "the Marcellus Shale is 'notoriously heterogeneous'" (Alpha, at 4). The request for a better description pertains to the overall area, not specifically the Marcellus shale. Additionally, the statement supports the concept that reported permeability values for the shale may not be representative and that broader scale description are required.

Hydraulic Connection between Shale and Surface

Alpha argues that the "target shales exist as an isolated system from the overlying fresh water-bearing units" (Alpha, at 4). "Isolated" overstates the case even for natural conditions, although the connection may be limited, as I accepted in 2009. Alpha claims that the "shales … are not part of, and are not connected to, the regional hydrogeological systems. Their baseline geologic evidence that fluid

migration to overlying fresh water aquifers is improbable includes studies that show the Marcellus shale has remained isolated from overlying formations for millions of years" (Alpha, at 5). Alpha does not directly provide citations for these "studies", but in the next sentence references the "facts that these units are 'overpressured' and that natural gas and saline water has remained trapped … for millions of years" (Id.) to two industry studies and the GEIS. This all ignores the science, cited in Myers (in review) of the upward movement and artesian pressure, observed during geothermal exploration, in formations above the shale. The salt in the shale may be the source of the salt in overlying formations, with the upward movement of salt balanced by the downward movement of freshwater recharge. This balance could be substantially upset by the changes wrought by fracking on the shale.

The "overpressuring" of the shale does not prove that the shale itself is isolated. Overpressuring is due to the gas being contained in the low permeability, very small pore spaces of the shale. Once fracked, the overpressuring may provide an initial source for water to flow into the formations above the shale.

The isolation argument is invoked again, by Alpha, at 11&12, 20, and 33.

My discussion relied and continues to rely for the 2011 rDSGEIS on the fact that fracking will change those conditions, changing the shale from an almost impervious aquitard into a low-conductivity formation; the previously isolated formation water will no longer be "isolated" because fracking fluid injection will push some into surrounding formations. The "overpressuring" in the shale may suggest that the shale itself is isolated at least in places. Myers' (2009 and in review) argument relies on the connection in the formation above the shale. Once fracked, the shale will have a much higher permeability so that fluids in the shale can move into surrounding formations within which the general groundwater flow will control.

Alpha refers to the fact that shallow water wells may be hydrofractured as "additional evidence that natural fractures and structures are not necessarily transmissive" (Alpha, at 4 and 37). This is a comparison of "apples and oranges". Hydrofracturing water wells may be done to increase their yield when screened in low-transmissivity formations; fracking water wells is done to increase the well yield from a few gallons per minute. The transmissivity of unfracked shale is orders of magnitude less than that in the formations in which a water well may have been screened. The cause for fracking in water wells differs from the cause for fracking a gas well; the comparison is irrelevant and proves nothing about the isolated nature of shale.

A further reliance on "overpressuring" is demonstrated (Alpha, at 5) where Alpha notes that eight research wells in the Marcellus shale had pressure gradients of 0.46 to 0.51 psia/ft when hydrostatic pressure is 0.433 psia/ft. That waters remain contained in the shale even with this overpressuring demonstrates their isolation. Once fracking hydraulically connects the shale with the overlying formations, the overpressuring is a source of pressure that would cause an upward gradient. The pressure would likely dissipate with time, but it would also cause an upward gradient after fracking.

Alpha indicates that my "hypothetical pathway … to ground water is along faults and fractures that intersect the Marcellus or induced fractures that extend beyond the target formation" (Alpha, at 5). This mischaracterizes the argument in two ways. First, it ignores the potential flow through the bulk media, through the primary porosity of the formations; this pathway would be slower, but flow is possible if there is a connection (Myers, in review) with the newly fractured shale. Myers (in review) found this flow to require from 100s to 1000s of years for contaminant transport. Second, natural faults and fractures do not have to "intersect" the shale, just reach its edge. Fluids within the shale would access the natural fractures above the shale, once fracked; the overpressuring would provide an added gradient for flow from the shale to surrounding formations, once fracking releases the fluids.

Alpha's second point is correct; out-of-formation fractures would provide an additional pathway. Although Alpha continues to suggest that out-of-formation fracking is rare, in their view, more current evidence is that it occurs frequently and extends as much as 2000 feet above the target formation (Fischer 2010); Alpha even references a personal communication from Fisher (Alpha, at 24) to recommend that the "SGEIS acknowledge that hydrofracturing has been shown to induce fractures beyond the target formation" (Id.). It appears that Alpha is not familiar with up to date literature or science.

Alpha rejects the "suggestion of 'head level maps'" that I had suggested in 2009 based on their rejection of the concept of saturated conditions from the "top of the target zone to the land surface" (Alpha, at 20). If there is no connection, groundwater levels will show nothing. They also note the isolation argument (at 20, 21) to reject the need for head level maps. Head level maps as recommended by Myers (2009) would confirm or deny the presence of upward head gradients in the formations above the shale. Once released by fracking, contaminants could advect along the flow paths which would be delineated by the hydraulic gradient. Although the fracking itself will change the gradient and potentially increase the potential upward flow, mapping the groundwater levels would assist the NYSDEC in determining where transport is possible. Alpha's recommendation is to basically ignore science and ignore the possibility of upward flow. Alpha replied to my comment suggesting that the rDSGEIS discuss properties resulting from fracking by discussing the direction that fractures would take in the shale (Alpha, at 15). My comments indicated that the rDSGEIS should include hydrogeologic properties, therefore Alphas reply was not responsive to the comment. Alpha's response that my "argument that the fractures will extend to and connect overlying fractures or paleofractures contradicts rock mechanics principles and field observations" is countered by the recent data in Fisher (2010) showing out-of-formation fracking. Alpha is unclear and provides no references as to how the comments contradict "rock mechanics principles".

I had also recommended that the NYSDEC require the industry to monitor post fracking shale properties. Alpha states that "[f]racture monitoring is required by the Proposed Supplementary Permit Conditions … (#33 and #34)" (Alpha at 16). That is incorrect; those permit conditions require the driller report on recorded operations during fracking, including pressure and the amount of injected, but that is not the same thing as doing post-frack monitoring, which could include microseismic surveys or core sampling. They also suggest that "[f]racture monitoring also can be evaluated on a well-specific basis using the

same criteria as the requirement to collect core samples and well logs" (Alpha, at 16). Those requirements are for pre-fracking conditions, not post-fracking.

Myers' Groundwater Modeling and ICF Analytical Modeling

I prepared (Myers 2009) an interpretative numerical groundwater model to consider whether and over what time frame flow could occur from the shale to freshwater aquifers. The "theory supporting Myers' model" is NOT from Hill and Tiedeman (2007) (Alpha, at 23). The reference is to the concept of "interpretative" modeling as opposed to a calibrated, predictive model. "Myers acknowledges that his model is not calibrated and cannot be used for predictive purposes" (Alpha, at 12). An interpretative model is not used for prediction, so Alpha's attack on the model is an attack here is irrelevant. The model does assume that the interburden between the ground surface and top of the shale is saturated, but not through the "isolated shale gas formations" (Id.). Again, the modeling is of the interburden and the shale, once it is fracked to its edge or beyond, is a boundary or a source of both fluids and contaminants. Or, flow through the shale is estimated based on its extremely low in-situ conductivity.

The numerical model I used in 2009 was not "to support [my] opinion" (Id.) but to test my conceptualization as to whether the flow was possible and under what conditions. Alpha criticizes the fact the model "oversimplifies ground water flow and transport". All groundwater models simplify flow; simple applications of Darcy's law are the most oversimplified analyses. The addition of secondary permeability, or fracture flow, to a contaminant transport analysis usually increases the rate that contaminants move, thus my estimated times should be low.

Alpha asserts that my "offered alternate model is not technically defensible" apparently based on their perceived lack of a hydraulic connection. They state that an assumption of a hydraulic connection "contradicts decades of hydrofracturing data and experience in the U.S." (Alpha, at 11) without referencing or outlining the data in support of their contention. They also claim that my analysis is based on "the entire bedrock stratigraphic column [being] highly fractured" (Alpha, at 12). This statement does not reflect the analysis in Myers (2009), for reasons noted above - the conductivity values used for the formations between the shale and surface were based on observed primary conductivity values (Anderson Woessner 1992), not fractured values.

ICF's flow equations are correct (Alpha at 11), but the problem is how they were parameterized and time frame they were applied over. As Myers (2009) discussed, the relevant gradient is not from the well to the aquifers, but from the well to just beyond the influence of the spreading injected fracking fluid, the point at which the background pressure has not changed. Also, the conductivity parameters for the formations between the shale and the aquifers do not reflect fractures, unless specifically parameterized as such. The parameters reflect standard textbook bulk conductivity values for sandstone.

Vertical Contaminant Transport

I had argued that "natural gradients" would allow vertical contaminant transport of frack fluid through advection. Alpha claims that "Engelder refutes that injected frac water would migrate vertically upward

in his slide-presentation review of others" (Alpha, at 24). Aside from the confusing phrase, "slide-presentation review of others", this line of reasoning cannot be correct because frack fluid is lighter than the high-TDS brine found in the shale; buoyancy due to frack fluid being lighter than brine would enhance its upward movement. The movement of high-TDS formation water could be inhibited by its denser nature, but the point is that upward hydraulic gradients cause the flow. The overpressuring discussed above is proof of these upward gradients and suggestive that fracking would release some of this pressure into the formations lying above.

Engelder's "principle of viscosity" (Id.) may apply "to ground water as well as gases", but the fact that low viscosity gases have been contained from vertical migration for millions of years does not mean that fracking will not release contaminants that could migrate upward much quicker. The relevant "containment" is provided in the shale and has nothing to do with the properties of overlying formations. Shale has contained gas for millions of years; fracking will cause that gas to be released in 30 to 50 years (the length of time most wells will produce). This can only occur if the properties that contain the gas will vastly change.

Leaks from Well Bores

The DSGEIS had implied that leaks do not occur from properly-constructed wells, but did not specify how often wells are found to not be properly constructed, and I requested (Myers 2009) that they provide an estimate of the times the wells are not properly constructed. Alpha responded with a quote from an industry source that estimated risk from failures to properly constructed wells is less than one in 50 million (Alpha, at 32). Alpha should have included the entire paragraph from which they selectively chose their quote, because it indicates the wells considered are class II injection wells and are properly constructed. Fracking wells experience a much higher, although much shorter, pressure during operations. They also should realize that the comment had to do with wells that are improperly constructed, because most failures, those that have allowed gas into groundwater, have resulted from improperly constructed wells.

Alpha also protests too much when they discuss my examples of gas in water wells (Alpha, at 33, 34). Incidents not related specifically to fracking are relevant because they show that the gas does move long distances through the groundwater, regardless of the source. Coal bed methane development relies on the gas moving through the groundwater, in coal seams, to the production wells; those production wells commonly pump as much water as do water wells, so, if gas is present to move to the water wells, the conceptual model for flow to water wells is similar. The point has to do with gas moving through aquifers due to any source – direct from the shale or a leak from the well bore.

Comparison to CBM Wells

Alpha used the conclusion to the EPA's 2004 CBM study, that fracking in coal seams poses little or no threat to underground sources of drinking water (Alpha, at 20) to support their conclusion that I had ignored relevant data (EPA's study) and that my arguments were fallacious because CBM wells are a much higher risk. They also state that "[c]oalbed hydrofracturing events approximate conditions where shale hydrofracturing is performed closest to ground water resources" (Id.). This is simply not true, and

it directly contradicts the conditions that the EPA put on their conclusion. EPA relied on the nature of CBM wells for their conclusion. "Although potentially hazardous chemicals may be introduced into USDWs when fracturing fluids are injected into coal seams that lie within USDWs, the risk posed to USDWs by introduction of these chemicals is **reduced significantly by groundwater production and injected fluid recovery**, combined with the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation" (EPA, 2004, at 7-5, emphasis added).

In fracked shale, there is no intentional "injected fluid recovery" brought about by pumping the injection wells, as in CBM wells. CBM wells pump water toward the gas well; this pumping decreases the hydrostatic pressure which releases the gas from the coal. Water and contaminants in the coal seam flows toward the CBM well. If there were contaminants in the coal, they would be drawn toward the CBM well.

Fracking in a coal seam would require much less pressure as well which would cause less out-of-formation fractures, which would limit the chance for out-of-formation fractures to occur. Additionally, EPA relies on the "high stress contrast between adjacent geologic strata" as a barrier to fracture propagation. The fact the coal is softer and the seams are much shallower and require much less fracking pressure helps to limit the fractures to the coal, much in contrast to shale seams (Fisher, 2010).

Finally, although the EPA's reasoning is reasonable, their methodology for concluding there has been no contamination is suspect; they only considered reported cases of contamination rather than relying on monitoring data. Fracking fluids in water wells near coal seams would be reported only if someone detects a problem. There have been cases of methane reaching water wells in the coal seams, but methane is obvious as it bubbles coming from the faucet.

Alpha claims that "Myers fails to address the historical data presented by ICF (2009, p. 22)" (Alpha at 19). ICF (2009, p 22) does not actually present data, contrary to Alpha's allegation. GWPC (1998), the source of ICF's "data", presents the results of a survey to which officials from states with over 10,000 coal-bed methane wells had responded they had never found groundwater contamination. However, contrary to Alpha's allegation, GWPC did not analyze 10,000 wells' worth of data. GWPC does not present monitoring data as proof, they present survey data from agency personnel claiming there has been no reported contamination. There is no indication whether the agencies ever looked for contamination beyond the claims of well owners. ICF also notes that coal seams may be used as aquifers, but did not indicate how many of the coal seams being developed by the CBM wells in the states replied to by the agency personnel were also aquifers.

Alpha truly mixes apples and oranges by using studies of CBM development, including fracking, to conclude that shale-gas development poses no threat to groundwater.

General Hydrogeology

Alpha's response to comments regarding aquifer depletion is a stretch to show how they actually disagree with my comments. Specifically, my comments about failures to regulate are replied to by stating the various commissions must permit the withdrawal – the problem is that there are really no

specifics provided about how the decision to permit would be granted. The DSGEIS did not specify what standard had to be met, beyond simple reporting, to be granted a permit.

Mitigating Surface Water Impacts

Alpha goes out of its way to find something to criticize in its review of my general surface water comments (Alpha, at 44, 45). My comments were generally qualitative and Alpha's responses are generally not substantial enough to require a reply here.

In Alpha section 4.2, regarding the use of the natural flow regime method, Alpha states that I was incorrect in claiming the NYSDEC would not require its use (Alpha, at 48). The 2011 rDSGEIS states clearly that it is NYSDEC's intent to require use of the NFRM, but the 2009 DSGEIS only states that it is "preferred", not required (2009 DSGEIS, at 7-3).

Alpha responds in detail to my comments regarding the Delaware and Susquehanna River Basin Commissions' methods (Alpha at 46, 47), even though they acknowledge the dSGEIS would require the NFRM. Because the rDSGEIS states the NFRM will be used throughout the project area, there is little reason to reply further to Alpha's comments at this point.

Ultimately, Alpha adapts many of my recommendations regarding surface water flow (Alpha, at 50, 51). They do not specifically endorse the recommendation to minimize the effect on aquatic habitats (outlined at Alpha, p. 47), the RDSGEIS does adapt a recommendation for using the Q60 or Q75 flow by month, which by month is better than my original recommendation.

Setbacks

Alpha discusses vertical setbacks along with my comments on monitoring and the need for water level mapping (Alpha, section 3.1). Much of their response relies on their perceived lack of hydraulic connection among formations, which has been discussed above.

Regarding horizontal setbacks, I had suggested that the recommended values are not based on any data or analysis of their effectiveness. Alpha simply rejects this without providing any reference, data, or results. "Myers assumes the setbacks proposed in the dSGEIS are not based on analysis; however, the setbacks are supported by practical application, experience, and historical analyses" (Alpha, at 43). Alpha repeats this sentence twice, verbatim, on the same page. When stating something as being based on analyses, it is customary scientific practice to cite the references to these analyses, something Alpha has failed to do. Alpha also suggests the "dSGEIS reference SEQRA, NYSDOH, NYC Watershed Rules and Regulations, the Clean Water Protection Act, and public water protection rules from other states" (Id.). Alpha does not indicate where in the dSGEIS these references are made, not indicates that the references include any analysis. Referencing others' rules without analyzing their effectiveness is not a scientific justification for specifying a setback. My statements are not that the setbacks are wrong, but that it is unknown whether they are effective. My recommendations may be larger than those in the dSGEIS, but they are designed to be protective to encourage a site specific analsis.

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Attachment 3

Glenn Miller, Ph.D.

Review of the

Revised Draft
Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program
Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Prepared for:
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January 6, 2012

This document represents a review of the Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) regarding proposals to develop natural gas wells using high-volume hydraulic fracturing in New York. I have specifically examined some of the chemical and toxicological issues, particularly related to the fracturing additives used, and the management of the severely contaminated flowback/produced brines. The RDSGEIS, in general, is an improved document compared to the previous draft of the potential environmental impact of the very large number of gas wells being proposed in much of New York. However, several key potentially significant adverse impacts remain inadequately addressed.

The following comments should be considered.

A. The water that flows back immediately following hydraulic fracturing is heavily contaminated (flowback), primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The brines that will be produced during gas production[1] will have higher concentrations of naturally occurring contaminants than flowback water (although lower volumes) and similarly represent a serious chemical contamination potential.

The RDSGEIS recognizes these problems and goes a long way towards evaluation and management of the contaminants; however, it still does not present a comprehensive wastewater management and disposal plan that will handle the anticipated large volumes of heavily contaminated wastewater. Further efforts are required to properly understand the contaminants in the flowback water, and develop management and disposal solutions.

Four problematic components of the flowback water and produced brines are present, including: (1) salts, other inorganic constituents, and metals and metalloids; (2) the radioactive component (NORM); (3) organic substances (from the hydrocarbon formation) and (4) hydraulic fracturing chemical additives.

1. ***Salts, other inorganic constituents, metals and metalloids in the formation water that are brought to the surface both as flowback and as production brines*:** The largest mass component of the formation water is salts and other inorganic constituents. The concentration of these constituents varies widely, as does their toxicity. Because the flowback is proposed to be collected and temporarily stored in closed systems, disposal of these large volumes of water is the largest problem with its management. The RDSGEIS discusses the problems with management of this water, and in

[1] The terms produced brine, production brine, produced water, and produced water brine are used interchangeably throughout these comments for formation water that is produced up the well.

particular the discharge of high total dissolved solids (TDS) water into receiving waters (see, for example pages 7-63), and stipulates that flowback produced water and brines will need to be regulated as industrial wastewater.

Table 5-10 of the RDSGEIS shows that produced waters (from Pennsylvania and West Virginia) containing the formation water are variable in chemical composition, but include not only simple salts (e.g., sodium, potassium, chloride, bromide, sulfate, fluoride, etc.) but also a variety of metals with varying frequency (cadmium, mercury, cobalt, nickel) and metalloids (arsenic, selenium, boron). Some of the constituent concentrations are very high, particularly sodium chloride, which has a mean concentration of over 10% by weight. Some samples had over 30% by weight simple salts plus other contaminants. The extreme contamination of these wastewaters and the high variability of contaminant levels make these waters complicated for treatment and potential reuse, as well as for tracking and disposal. If improperly managed and released to surface or groundwater, severe contamination is a reasonably foreseeable outcome. In particular, if this contaminated water intercepts domestic groundwater sources, the potential exists to permanently damage aquifers as current and future domestic water supplies.

While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of treatment and disposal alternatives, the RDSGEIS does not sufficiently analyze the environmental or human health impacts associated with any of these treatment and disposal options. Further, the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state, where regulations may be less stringent, due to the lack of treatment capacity for these contaminated waters in New York.

2. ***Radioactive Substances (NORM):*** The RDSGEIS also recognizes the issues associated with management of NORM that comes to the surface either in the flowback or the production brines. However, similar to the salt problem discussed above, it does not explicitly indicate how wastes contaminated with NORM will be regulated and disposed.

   Examples of NORM concentrations in flowback are presented in Table 5-24, and in produced brines in Appendix 13. As expected, the NORM present in the flowback is somewhat lower than in the brines, due to dilutions when fresh water is used for the primary fracturing fluids. Less dilution would be expected if the flowback is reused as a portion of the fracturing fluid for another well.

Only three produced brine samples are shown in Appendix 14, but the level of radioactivity as gross alpha is very high, from about 18,000 pCi /L to 123,000 pCi/L. The standard for safe drinking water is 15 pCi/L (gross alpha).

The RDSGEIS does not propose a disposal solution for residual NORM, if it is separated from the produced water and the flowback water. Dilution of the brines to a drinking standard of 15 pCi/L (gross alpha) will require 1000x to 10,000x dilutions, and is unlikely to be acceptable in any jurisdiction, particularly when the components that are causing the radioactivity are not specified. While some mention of regulatory oversight is made in the RDSGEIS, there are no explicit indications of how these waters will be regulated or managed. The RDSGEIS does not propose a technically sound or viable solution for disposing of these radioactive materials. The RDSGEIS has not examined options such as evaporation-crystallization treatment or chemical precipitation. These processes will produce a very large tonnage of salts containing radioactive and metal waste. The lack of a thorough treatment and disposal analysis presents a serious problem when assessing the risk and potentially significant adverse impacts of these substances. There is effectively no analysis of how these materials will be disposed, other than a general (potential) suggestion that new licensing may be required.

For an adequate environmental analysis, it is also critical to identify the sources of the gross alpha radiation. Gross alpha radiation is defined by the U.S. EPA (40 CFR Parts 9, 141, and 142 [National Primary Drinking Water Regulations; Radionuclides; Final Rule]) as the total amount of alpha radiation minus the alpha radiation coming from uranium and radon. Table 2.3 of the RDSGEIS, which specifies the primary drinking water standards, is unclear as to how New York regulates radioactivity, other than to indicate that it will limit "alpha particles" to 15 pCi/L in drinking water, but does not indicate if that includes uranium. For the three samples of groundwater indicated in Appendix 13, only a small fraction of the components of the gross alpha have been identified, with the largest component being ^{226}Ra. For the three samples provided in Appendix 13, the individual gross alpha contributors can be summed to provide only 14-24% of the gross alpha in the water samples. The RDSGEIS does not identify the source of the remaining 76%+ alpha radiation; this omission constitutes a major flaw in the radioactive waste treatment and disposal analysis.

While it may be difficult to get an exact mass balance, accounting for less than 25% of the alpha radioactivity is insufficient.

It is unclear whether the data in Appendix 13 were based on the EPA gross alpha radiation definition, but the implications are substantial. If the EPA gross alpha radiation definition is used (which is probably the case), some other source of the alpha radiation will be present (e.g., polonium) as was

observed in the Florida phosphate industry (Burnett, et al., 1988). Verifying radioactive waste constituents is particularly important when assessing radioactive waste risk and to develop viable treatment and disposal options. Radioactive materials will also precipitate as scale in equipment; therefore, verifying radioactive waste constituents is also important for determining the radioactive risk as pipes are disassembled when cleaning is needed, or when the wells are disassembled when gas production ceases. If the source of the excess alpha radiation is polonium, the residual radioactivity from water treatment or scale management will potentially be more expensive to manage safely. The RDSGEIS has not analyzed the polonium risk, or treatment and disposal options for radioactive waste containing polonium.

While the U.S. does not have a polonium 210 standard, both Canada and the European Union do (see accompanying comments of Dr. Ralph Seiler), and it is lower or similar to the U.S. radium standard (5 pCi/L). Polonium is soluble in water under reducing conditions, and should be assumed to contribute to the alpha emission from the formation water, unless NYSDEC can rule out the risk. Polonium's risk contribution, however, is not currently analyzed in the RDSGEIS, and is a critical data gap in the NORM analysis. Polonium is a strong alpha emitter, but most importantly, treatment/management of these waters for disposal should require knowledge of the composition of the alpha emitting NORM component. Only then can appropriate methods for treatment and disposal be developed.

An additional component of the naturally occurring radioactivity is radon, a gaseous odorless radioactive element that is responsible for approximately 21,000 deaths from lung cancer each year (ATSDR, 2012), and is second only to cigarette smoking for causing this disease. Southern New York is already recognized as a region where elevated radon (>4 pCi/L) is common. Adding radon to households either from improperly vented gas utilizing appliances or through water systems that have been contaminated with natural gas leaks in groundwater supplies presents an additional risk factor for radon.

Data on radon in natural gas from the Marcellus Shale formation is very scant, and the RDSGEIS does not contain a sufficient amount of data to verify the maximum concentrations of radon expected in Marcellus Shale gas, or any other natural gas that may be developed under the proposed scope of the SGEIS. The amount of radon in natural gas is a critical measurement that should be made, to examine the incremental risk of radon exposure in homes and places of business that use natural gas or well water that could experience higher radon content as Marcellus and other shale gases are produced in NYS. While normal natural gas use in properly ventilated burners is unlikely to contribute to radon concentrations in closed spaces (see accompanying Seiler report), poorly vented areas may result in increased radon concentrations, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners)

should be subject to risk assessment. The risk of radon exposure from burning natural gas in poorly ventilated areas is likely to be greatest in indoor areas that already have elevated radon exposure levels.

An additional risk is when natural gas from a well leaks into an aquifer used as a well water source. Depending on concentrations of radon in the water, and the use of that water, radon levels can potentially be elevated in homes. This is a separate risk than from burning natural gas, but it is reasonable to develop scenarios where highly radon-contaminated gas moves through the soil profile and into homes. However, there are only scant radon data that can provide a basis for estimating those risks.

Recommendation 1. The SGEIS should clearly identify treatment and disposal options for flowback and wastewater, analyze the range of treatment and disposal alternatives, and propose the best technology and best practices for handling this waste. These technologies and practices should be included in the SGEIS as a mitigation measure, and codified in the NYCRR. The SGEIS treatment and disposal options for flowback and wastewater analysis should include a detailed examination of the waste constituents including, at a minimum: salts and inorganic constituents; NORM; metals and metalloids; organic substances (from the hydrocarbon formation); and fracture treatment additives.

Recommendation 2. The SGEIS should examine the existing wastewater treatment capacity in NYS, compared to the potential volume and composition of wastewater that will be generated by the proposed development, and make specific recommendations to ensure sufficient waste handling capacity exists before authorizing the proposed development. If waste will be transported to other states, the SGEIS should examine the impacts of that waste handling option as well.

Recommendation 3. The components of the gross alpha radioactivity should be identified in the RDSGEIS, and mitigation measures should be proposed to address radioactivity risk. The RDSGEIS does not identify 76%+ of the gross alpha radioactivity. The specific definition of gross alpha radioactivity should also be stated, or the EPA definition should be used.

Recommendation 4. The RDSGEIS should determine whether polonium is a significant component of alpha emission in formation waters, and polonium-contaminated wastewater should be regulated/managed appropriately to limit its discharge to surface or groundwater, as should all of the individual components of NORM.

Recommendation 5. Specific treatment methods to remove radioactive constituents from flowback and produced water need to be identified. If the radioactive constituents are removed from wastewater, management methods and disposal sites for the residual radioactive wastes should be identified. (See further discussion below.)

Recommendation 6. Additional radon measurements are needed to determine the range of concentrations of radon expected in Marcellus Shale gas or any other gas that may be developed under the proposed scope of the SGEIS. Gas measurement should be made at the wellhead, where natural gas is being used, including homes, businesses that use large amounts of natural gas, and in areas where natural gas leaks have been found. The SGEIS should include radon testing requirements as a mitigation measure, and this requirement should also be codified in the NYCRR.

3. ***Hydrocarbons present in the formation water:*** Hydrocarbons present in the flowback and produced water are characteristic of fuel hydrocarbons, and are represented by (a) compounds that, in some cases, are carcinogenic (e.g., benzene, benzo(a)pyrene); (b) common solvents (e.g., toluene, ethylbenze); and (c) the primary fuel components of natural gas, particularly methane. Common solvents and primary gas components, although generally of lower solubility in water, represent a toxic contribution that can be a serious risk, if they are released either into surface water or as a vapor that may subject persons living in the area to exposure.

4. ***Hydraulic fracturing additives:*** The range of hydraulic additives is very large, and difficult to assess from a risk perspective since the list is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives and the amounts provides effectively no basis for estimating the risk of these components of the flowback or produced water, and the RDSGEIS falls seriously short in this regard. A mere laundry list of these components does not meet requirements for analysis of their potential impacts. The list is so long, and the data on each component so incomplete, that it falls far short of the data that would normally be contained in a professional scientific risk analysis. Additionally, Tables 5.4 and 5.5 use trade names, and while the New York regulators may have information on the constituents in those products, that information was not available for this review. Additionally, the public does not have access to this information, and thus the public cannot legitimately understand or evaluate the risk of these products to their health or the environment that they live in.

   Table 6.1 reports the constituents found in flowback, and effectively none of the additive compounds used in fracturing were reported in the flowback, except for the hydrocarbons that occur naturally in the hydrocarbon formations (benzene, toluene, xylene, naphthalene, etc.). In fact, the only non-fuel compound found in flowback that is also mentioned as a hydraulic fracturing additive is propylene glycol. This analysis demonstrates a significant problem in examining flowback chemical composition. Either NYSDEC is concluding that chemicals injected into the formation do not return in the flowback (improbable), or NYSDEC has not employed the correct analytical methods to evaluate flowback waste constituents.

It is not clear from the RDSGEIS how many of the additives were actually subjected to analysis in the flowback samples. Most of the chemicals listed in Table 6.1 that are used as additives will not be detected/measured by the standard methods used to determine hydrocarbons and metals. Therefore, the absence chemical additives in the flowback samples shown in the RDSGEIS is likely a function of incomplete laboratory analysis. For example, it is not clear that any attempt was made to actually measure the following three compounds in the flowback water: (1) 1-propanesulfonic acid; (2) 2-propenoic acid, homopolymer, ammonium salt; (3) acetic acid, hydroxyl-, reaction products with triethanolamine. None of the methods used by the Marcellus Shale Coalition (see Chapter 5-109) would, in this reviewer's estimation, be suitable for measuring these compounds. In fact, many, if not most of the additives, require very specialized methods for analysis; some are multiple chemicals (e.g., polymers), and some are relatively unstable (e.g., acrylamide).

There is, however, an implication that since the compounds were not subject to analysis, and thus not observed in the flowback water, they do not exist in the flowback water, which is a scientifically unjustified conclusion and almost certainly not the case.

Table 6.1 should be re-created with an additional column that indicates whether the compounds would have been measured with the analytical scheme utilized (e.g., gc-ms, icp-ms, ion chromatography for anions, etc.). Additionally, the RDSGEIS should list the analytical method required to detect each compound in the flowback. The detection limit for each method should be specified.

A full analysis for all of the additives utilized in hydraulic fracturing is indeed a challenge, but the SGEIS should clearly indicate which compounds could be measured by the protocol utilized, which could not, and what method would be required. It is likely that most if not all of the additives used that are not found in the formation water were not actually measured/determined. Thus, Table 6.1 has very limited value, and provides a distorted view of what is actually being measured.

Recommendation 7. The analytical tables for hydraulic fracturing additives should be revised to clearly show the analytical methods utilized and whether the analytical methods used, and detection limits provided by those methods, are sufficient to protect human health and the environment. The tables should verify if the additives were actually measured in the flowback water.

Recommendation 8. The RDSGEIS should include as a mitigation measure a list of analytically testing methods required to test flowback prior to disposal; these testing requirements should also be codified in the NYCRR.

A detailed risk assessment of each of the potentially toxic additives is a reasonable request. Leakage of flowback water to domestic water has been demonstrated recently in Wyoming by the U.S. EPA (2011) and represents a potential threat to ground water in New York. It is not sufficient to simply argue that gas wells will not leak, since leaks are now apparent in certain well fields (e.g., most recently in Wyoming (US EPA, 2011a)), as well as in Pennsylvania (Pennsylvania DEC, 2011). When leaks occur, it is probable that the greatest risk will be from the naturally occurring substances, but the additives also pose a non-trivial risk.

Practically speaking, it is more efficient and cost-effective to limit the additives used, rather than test for every possible additive in the flowback. Other governments and agencies have developed simplified methods and lists for prohibiting toxic additives, and assessing their risk (e.g., OSPAR PLONOR, C-NLOPB Guidelines, The Norwegian Pollution Control Authority; see accompanying report of Susan Harvey regarding additives). NYS could develop a similar list of prohibited additives, and a process for approving additives for use that will offer a method for reducing risks to both the public and workers.

Some of the additives being used are serious carcinogens, and may be difficult to measure. Two examples of these are acrylamide and acrylonitrile. Both are carcinogenic and, while not long lived in the environment, can create serious exposure concerns to workers and the public.

Acrylonitrile has been found in Pennsylvania and/or West Virginia in water samples taken near hydraulic fracturing operations (data received from individuals who had samples analyzed). It was also observed in flowback water from the Marcellus Shale Coalition (page 5-115 of the RDSGEIS). Acrylonitrile is a carcinogenic (US EPA, 2011b) and exclusively anthropogenic compound. It can be measured in a standard purge and trap gc-ms method, and has been used in Pennsylvania, and is indicated in a patent issued to Halliburton (Halliburton Energy Services, U.S. Patent 7799744). This compound is one of the more toxic compounds used as additives, yet is not even mentioned in the RDSGEIS (Table 5.9). Failure to include a chemical additive that is commonly used and known to be carcinogenic and toxic to humans is a serious deficiency in the RDSGEIS.

Failure to include Acrylonitrile in Table 5.9 raises uncertainty in what other harmful chemical were not listed or examined in the RDSGEIS. Additionally, the RDGSEIS lacks of information on additives use rates. Therefore, the RDSGEIS analysis of the potential significant adverse impact of additive use is, at the least, incomplete.

Acrylonitrile, butadiene and styrene (ABS polymer) are mixed "on the fly" with the uncoated propping agent to create a polymer covering on the propping agent. From the Halliburton patent:

> Some suitable polymers include, but are not limited to, acrylic polymers such as acrylonitrile polymers, acrylonitrile copolymers, and mixtures thereof. Some preferred polymers include homopolymers and copolymers of polyacrylonitrile (including copolymers of acrylonitrile and methyl acrylate, methyl methacrylate, vinyl chloride, styrene and butadiene), polyacylates, polymethacrylates, poly(vinyl alcohol) and its derivatives, and mixtures thereof. As used herein the term "acrylic" polymers refers to any synthetic polymer composed of at least 85% by weight of acrylonitrile units (the Federal Trade Commission definition). Thus, the definition of the term may include homopolymers of polyacrylonitrile and copolymers containing polyacrylonitrile. Usually they are copolymers of acrylonitrile and one or more of the following: methyl acrylate, methyl methacrylate, vinyl chloride, styrene, butadiene. However, polymers that do not meet the definition of an acrylic polymer (such as those having less than 85% acrylonitrile) may also be suitable. For instance, Example 3 uses poly(acrylonitrile-co-butadiene-co-styrene) that contains approximately 25 wt % acrylonitrile.

Further down the patent, the "on-the-fly" process is described.

> In particular embodiments of the present invention, the particulates may be coated with the polymer solution and introduced into the treatment fluid, which acts as the aqueous medium, directly prior to being introduced into a subterranean formation in an on-the-fly treatment.

This process is likely to be inefficient and likely to release substantial amounts of acrylonitrile and styrene into the water used in the fracturing process. Acrylonitrile has been found in flowback water (page 5-115 of the RDSGEIS), and reports are available that show that it has been detected in surface and ground water in Pennsylvania, and is perhaps one of the most unambiguous anthropogenic indicators that off-site contaminated water has been in communication with the water used in the fracturing process. NYSDEC should determine if this polymer and application method is appropriate for use in New York, and require acrylonitrile and styrene as two of the suite of compounds to be analyzed in flowback before it leaves the wellsite.

Recommendation 8. The NYSDEC should re-examine the additives used in hydraulic fracturing and conduct a much more detailed analysis of the risk of these compounds. Specifically , acrylamide and acrylonitrile, a carcinogenic and exclusively anthropogenic compound used in hydraulic fracturing, should be measured in flowback water, and an assessment made as to whether and/or how use of this compound should be permitted. The conclusions of such analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

B. The analytical data presented in Tables 5.10, 5.23, 5.24 and 6.1 all indicate a lack of detailed understanding of the quality of the flowback, and indicate

an inadequate understanding of the methods necessary to fully characterize the wastewater.

The errors in Tables 5.10, 5.23, 5.24 and 6.1 are sufficiently glaring that they need a much more detailed review. For example, in Table 5.10, the dissolved metal concentrations in some cases are higher than total metals. Iron, for example, has a median concentration 29.2 mg/L, but the dissolved median concentration is 63.25 mg/L. Similarly, the mean manganese concentration is 1.89 mg/L, while the dissolved manganese concentration is 2.975 mg/L. There cannot be higher amounts of dissolved iron and manganese than total iron and manganese.

The data from the Marcellus Shale Coalition was not displayed, other than as a table of compound detections. These samples were collected from 19 gas well sites in Pennsylvania and West Virginia. All samples were collected by a single contractor and the analyses performed by a single laboratory, which should reduce the variability. This would appear to be a very valuable data set, but surprisingly, no data were presented regarding concentrations of the analytes. Some comments were provided on the types of compounds detected, although it was not clear which types of water contained these constituents. Additionally, chlorinated hydrocarbon insecticides were detected, which is very surprising, since these compounds could not have been found in the formation water, and have not been used in the U.S. since the 1970's. They are likely false positives, although it is not possible to make that determination, based on the discussion in the RDSGEIS. Data obtained from the Marcellus Shale Coalition should be presented, which compares, for example, flowback water from different wells under similar conditions (e.g., immediate flowback versus flowback in subsequent days).

Finally, the data in Table 6.1, which focuses on the additives used in hydraulic fracturing, is problematic. As discussed above, it is highly unlikely that attempts to determine the concentrations of the fracturing additives were actually conducted, since many of these compounds are difficult to determine. The implication remains, however from Table 6.1, that these compounds were actually considered in some appropriate analytical scheme. This is almost certainly not the case, and Table 6.1 should be clarified.

Recommendation 9. Each of the SGEIS tables of analytical data should be reviewed by an analytical chemist, and the data be presented in a scientifically accurate and quality controlled manner. The data in Table 6.1 should be clarified and the compounds which were not subjected to specific analyses should be identified.

C. Permissible treatment of the flowback and the produced water is not well defined. It is unclear how the post-treatment residual salts and radioactivity will be managed. There does not appear to be any complete treatment of these waters that will be permitted in New York.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, (3) treatment in municipal facilities, or (4) treatment in privately owned facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified.

"Treatment" of flowback for *reuse* is discussed in Section 5.12. Reuse of the flowback conserves fresh water and allows contaminated water to be used instead during fracturing. However, the RDSGEIS only considered treatments for removal of salts that would allow for reuse in other hydraulic fracturing operations, and evaluated how specific requirements for reuse could be met by various treatment processes (e.g., membrane, ion exchange or evaporative processes). It did not analyze the residual contaminants removed by evaporative or membrane processes and thus concentrated, or how those contaminants would be managed, other than to indicate that the residual salts, or concentrated brine will require "further treatment or disposal." The SGEIS must address how this highly concentrated and toxic residue will be regulated and managed.

Three hundred tons of salt will exist in one million gallons of flowback or produced water brine, if you assume a 7% (70,000 mg/L) salt solution. The source of the alpha emitters also must be identified, as is discussed above. If, as is suspected, polonium is present in the flowback water, it represents an additional management burden of the flowback and produced water that must be evaluated.

Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells (although there are currently no industrial waste injection wells capable of handling this wastewater in NYS), municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water), and private treatment plants (of which none currently exist in New York). Therefore the RDSGEIS examines options that do not exist, and does an incomplete job of that examination.

The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for treatment and disposal of flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with each treatment and disposal option.

Section 6.1.8.1 indicates that "[f]lowback water may be sent to POTW's", but then describes the limitations that may preclude disposal of these waters in POTWs. The RDSGEIS requires that a "facility must first evaluate the pollutants present in that source of wastewater against an analysis of the capabilities of the individual treatment units and the treatment system as a whole to treat these

pollutants" (page 6-57); however, before such an evaluation can be conducted, the well operator must obtain a complete analysis of the flowback water (which as explained above, has not been done).

Additionally, the diversity of the flowback water quality is such that a POTW would need to conduct an extensive and expensive analysis of each water type that was delivered to the POTW under those guidelines. Since most of the additives are clearly not subject to routine analyses, it appears doubtful that a POTW could ever accept this type of waste. Also, if the limitation of 15 pCi/L of radium in the influent is enforced, a large portion (as yet not determined) of the flowback water could not even be accepted. Finally, the requirement of a complete description of the contaminants in the water is likely to add an additional burden to using POTW's for disposal, that this option may be precluded for most of the flowback water. Therefore, the proposal to use POTWs as a potential treatment and disposal method is scientifically and technically unsupported.

One serious problem with the proposed discharge (dilution) of fracture treatment wastewater via a municipal or privately owned treatment plant is the observed increases in trihalomethane (THM) concentrations in drinking water reported in the public media (Frazier and Murray, 2011), due to the presence of increased bromide concentrations. Bromide is more reactive than chloride in formation of trihalomethanes, and even though bromide concentrations are generally lower than chloride concentrations, the increased reactivity of bromide generates increased amounts of bromodichloromethane and dibromochloromethane (Chowdhury, et al., 2010). Continued violations of an 80microgram/L THM standard may ultimately require a drinking water treatment plant to convert from a standard and cost effective chlorination disinfection treatment to a more expensive chloramines process for water treatment. Although there are many factors affecting THM production in aspecific water, simple (and cheap) dilution of fracture treatment water in a stream can result in a more expensive treatment for disinfection of drinking water. This transfer of costs to the public should not be permitted.

NORM, the inorganic substances, and the organic compounds from the formation also represent serious contamination potential and require an appropriate level of treatment. The exact method of treatment that NYSDEC expects to require for any municipal or private treatment facilities that may be permitted is unclear. The RDSGEIS suggests that there will be some level of wastewater dilution through discharge into a receiving stream, at least in some cases. The analysis should be much more explicit about how wastewaters will be treated, both in-state and out-of-state. New drilling operations should not be permitted until adequate management/disposal of these waters is evaluated, with public comment required on the proposed methods, an analysis of the impacts associated with each, as well as mitigation measures as required by SEQRA.

Injection of the waste fluids into fully permitted underground injection control (UIC) wells is an option also, although this method is problematic due to the lack of permitted wells in New York, and the distance the contaminated water would need to be trucked in order to dispose of it in other states where permitted wells exist (e.g., Ohio). The recent seismic activity in Ohio from disposal of fracturing fluids also raises serious concerns whether this option is safe. Given the difficulties of wastewater treatment, UIC is likely the popular choice for wastewater disposal from the Marcellus region. However, NYS' increase wastewater load, along with increased wastewater generated from the increased drilling in Ohio and surrounding states, will likely pose an injection capacity problem for Ohio UIC wells. The RDSGEIS has not examined whether it is possible, or safe to install disposal wells in NYS' or whether a nearby state has sufficient capacity to inject NYS' incremental waste load, or whether this is the best technical solution. These are all potential significant adverse impacts that should be, but are not, addressed in the RDSGEIS.

Out-of-state management of waste is contemplated in Section 5.13.3.3., but is identified as not being within the regulatory purview of New York. However, simply stating that wastewater will likely be managed "out-of-state" is insufficient. Wastewater handling is an unmitigated significant impact in the RDSGEIS as currently proposed. The proposal to export NYS' wastewater and not examine this significant impact is not justified.

NYSDEC should instead evaluate the impacts of, clear cradle-to-grave oversight and management, identify the best solutions for waste handling, and include those requirements as mitigation measures in the RDSGEIS.

Furthermore, even if some export of wastewater is permitted, SEQRA requires analysis of the impacts of any potential waste management options, even if they are to occur outside of New York.

Finally, road spreading for dust control and de-icing would apparently (and appropriately) not be allowed for flowback water, but could be used under certain conditions for the produced brines. A rationale for this distinction is not provided, and permitting road spreading of produced water is not recommended, since the brines will have higher concentrations of NORM than the flowback water, and may include polonium. Some rationale should be provided for this distinction, particularly since it is apparently unknown if any of the hydraulic fracturing additives are even detected in the flowback water (see Table 6.1). It is clear, however, that the NYSDEC is concerned about using the brines for roads and will require a specific permit for this application. Whether a permit will be granted presumably will depend on the amount of radioactivity present in the water. Under no circumstances should brine solution that has a gross alpha concentration of greater than 15 pCi/L be applied to roads. Ultimately, this practice should not be allowed – there are simply too many questions about the identity and amount of contaminants in these fluids.

Recommendation 10: The RDSGEIS should identify and evaluate the impacts of the various options that are proposed to be permitted for management of wastewater, and identify any proposed mitigation for identified significant adverse impacts, which should be set forth in the proposed regulations.

Recommendation 11. Specific influent contaminant load restrictions need to be explicitly identified including those for: fracking additives, NORM (including gross alpha), TDS and other relevant contaminants in this management description.

D. Cuttings disposal: Disposal of cuttings is considered in the RDSGEIS, although the treatment is incomplete. Cuttings from the shales of marine origin such as the Marcellus Shale (particularly the horizontal cuttings) will require further examination to determine if they contain large amounts of salts, similar to the produced brines, or if they contain excessive alpha emitters. While the measurements of radioactivity, based on a gamma detector, do not indicate high levels of radioactivity, further analysis is required to determine the leachability of these cuttings. Polonium is only a very weak gamma emitter, and thus it would not be observed by simple gamma counting. The organic (reducing) components of the shales chemically trap uranium and potentially other radionuclides, and when they are subject to oxidizing conditions, increases in the solubility/mobility of some of the radionuclides (particularly uranium) is likely. The leachability of these cuttings under oxidizing conditions thus requires further analysis, as discussed at the bottom of page 6-65. However, these determinations need to be made, and the risks and potential mitigation identified, *prior* to permitting the wells.

Recommendation 12. The RDSGEIS must fully evaluate the potential significant adverse impacts of cuttings disposal and identify any necessary mitigation to address such impacts, which should be set forth in the proposed regulations.

E. Odors are a continuing concern from gas wells: A variety of chemicals are present in hydrocarbon formations that can present a serious odor problem, which can be both a serious human health problem and affect the quality of life of persons living near these sites. A very common, but toxic, constituent is hydrogen sulfide, characterized by a rotten egg smell. Other organic sulfides can also be present, including a variety of alkyl sulfides. Odors are very difficult to regulate, due to the vagaries associated with odor detection, acclimation, and differential effects on different persons. The severity of an odor is in the nose of the beholder. Thus, each well should be assessed to determine the potential of migration of volatile substances from the well operation to surrounding residents. Odor complaints should be taken seriously, and the presumption should be that an odor complaint is valid, and an investigation of the source required.

Hydrogen sulfide is, however, probably the most acutely toxic component present in a potential natural gas leak, and it can pose a serious health risk to surrounding residents, in addition to causing odor complaints. Sulfide monitors should be required at least two points, corresponding to most probable downwind locations at the fenceline. When hydrogen sulfide is detected above the odor thresholds, the source of the odor should be identified and eliminated.

Setbacks from an operating well will help to minimize the impact of odors on the surrounding residents. (Setbacks are discussed in further detail in the accompanying reports being submitted under cover of the Louis Berger Group.)

Recommendation 13. The RDSGEIS must fully evaluate the potential significant adverse impacts associated with odors and hydrogen sulfide emissions, and identify any necessary mitigation to address such impacts, which should be set forth in the proposed regulations.

F. Monitoring of nearby domestic wells for contamination from gas drilling operations should be conducted at regular intervals during and following hydraulic fracturing. While the drilling company would be required to test domestic wells for contamination prior to gas development operations, these same wells should be tested during production, and subsequent to discontinuing production to determine if hydraulic fracturing has resulted in contamination (See the accompanying report of Dr. Tom Myers). At present, the documents are silent on this requirement and effectively transfer this responsibility to the well owner. The analytes that should be determined should include, at a minimum, the components of natural gas (methane, ethane, etc.) and also toxic volatiles from the formation water (benzene, toluene, xylenes), salts and relevant inorganic contaminants, and the additives used during the hydraulic fracturing. This list should be developed based on those specific additives used.

Recommendation 14. The RDSGEIS and proposed regulations should require that monitoring of domestic wells situated in close proximity to gas drilling operations to be required at regular intervals during and following hydraulic fracturing. Because of the slow movement of groundwater, routine analysis of those domestic wells should be continued at least 20 years.

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Attachment 4

Ralph Seiler, Ph.D.

Review of the

Revised Draft
Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

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1/11/12

This document represents a review of the Revised Draft Supplementary Generic Environmental Impact Statement (RDSGEIS) regarding the hydraulic fracturing proposals to develop natural gas wells in New York. I have specifically examined issues related to NORM in the flowback/produced brine, as well as of radon in the gas itself. My comments supplement those of Glenn C. Miller, Ph.D.

Issue 1.

Unidentified sources of gross alpha and beta radioactivity in flowback water and production brine.

Gross alpha radioactivity in the brines (Appendix 13) and flowback water (Table 5-24) can be very high. In the brines, gross alpha is usually from 8,000 to 20,000 pCi/L, with a maximum of 120,000 pCi/L (Well Webster T1). In the brine samples with high gross alpha, the sum of uranium (U) , thorium (Th) , radium-226 (^{226}Ra) and radium-228 (^{228}Ra activities is much less than the measured gross alpha. Individual analyses of flowback water are not given, but the aggregated data similarly suggest that the sum of U, Th, and ^{226}Ra and ^{228}Ra activities is also much less than the measured gross alpha. These results indicate one of two things:

1. There are analytical problems with the gross alpha measurements, probably caused by the high salinity of the water.
2. There is an unidentified alpha emitter present in the water.

High salinity can cause the measured gross alpha to significantly overestimate the actual alpha activity of a sample (Arndt and West, 2007). The recommended mass placed on a planchet for gross alpha is only100 mg, so given a brine Total Dissolved Solids (TDS) of 350,000 mg/L (p. 6-61), only ~0.4 ml of sample should be placed on a planchet. The high TDS means it is easy for too much mass to be placed on the planchet, or the small volume means the mass may be unevenly distributed. Both of these factors can contribute to reduced precision and accuracy in the gross alpha analysis.

Appendix 13 indicates all of the relatively long-lived, naturally occurring alpha emitters in the brines were measured except polonium-210 (^{210}Po). Radon itself would not contribute at all to the measured gross alpha because it is a gas. In the gross alpha measurement, an aliquot of sample water is placed in a planchet and evaporated to dryness. After drying, the planchet is commonly flamed until it glows red to drive off hygroscopic water from the salts. Because of this, alpha radioactivity from radon does not contribute to gross alpha radioactivity.

^{210}Po normally binds strongly to sediment particles and concentrations in fresh groundwater are typically <1 pCi/L. In some geochemical settings ^{210}Po activities have exceeded 500 pCi/L in drinking-water wells in the US (Seiler et al., 2011), however this is extremely rare and fewer than 100 US wells have been reported with >15 pCi/L. ^{210}Po is known to be present in oil-field brines (Parfenov, 1974), however, the reported ^{210}Po activities in the brines were relatively low, about 100 pCi/L.

On p. 6-205 the RDSGEIS states radium is the primary radionuclide of concern, but this may not be the case if the excess alpha radioactivity is caused by the presence of ^{210}Po. If ^{210}Po is present in high levels, it may be much harder and more expensive to treat the contaminated water and manage the waste. Ra can be removed from water with relatively simple technology such as water softeners. On the other hand, Charles County in Maryland found the best way to remove Po from a contaminated public-supply well was with reverse osmosis. Treating millions of gallons of brine with reverse osmosis would be expensive and difficult, and could increase the cost to the public if treated at a public treatment facility. It could cause the gas to be more expensive to the consumer if the operator is made to bear the cost of treatment at an on-site or privately-owned treatment facility.

Gross beta radioactivity in many of the wells in some of the wells is several thousand pCi/L. To evaluate the significance of this, you need to know the potassium concentrations because ^{40}K is the source of almost all natural beta. If gross beta minus a correction factor for K were to exceed 50 pCi/L in a municipal well, the operator would have to identify the major contributors to gross beta. One

potential contributor to gross beta is lead-210 (^{210}Pb), which was not measured. This is potentially important because ^{210}Pb decays to ^{210}Po and could support it in the water.

Issue 1 Recommendations

The cause of the excess alpha radioactivity in the brine and flowback samples needs to be determined. ^{210}Po may be present at high concentrations and could pose a significant risk to health and the environment if oil-field brines are inadequately disposed of because it bioaccumulates. Samples from some of the more contaminated wells should be reanalyzed for the same suite of analytes as before, except this time include ^{210}Po. Redoing the complete suite will provide an idea on how adequately the less expensive gross alpha analysis identifies the presence of ^{210}Po. All samples analyzed for NORM (e.g. p. 6-61) as part of the regulatory process should include ^{210}Po, at least until it has been demonstrated that ^{210}Po is not an important source of alpha radioactivity.

NYSDEC should identify what the important contributors to gross alpha are (probably radium and ^{210}Po) and identify how, if at all, the brine and flowback water will be treated, taking economic considerations into account. Failure to do so constitutes a potentially significant adverse impact that would not have been disclosed or mitigated.

The principal contributer to the gross beta radioactivity is probably potassium-40 (^{40}K), but this should be confirmed because ^{210}Pb can also contribute to gross beta, and if present ^{210}Pb can support aqueous ^{210}Po. An estimated ^{40}K activity, based on the potassium (K) concentrations for the brines, should be added to Appendix 13 so the gross beta measurements can be evaluated. It is presumed that K was measured, even though no major ion analyses for the brines were found in the RDSGEIS. A theoretical activity ratio of 0.818 pCi/mg was reported by Friedlander et al. (1981) and can be used to convert concentrations to activities.

Issue 2.

Documentation of analytical methods

It is important that all analytical methods that will be used to analyze pollutant levels are well documented, but the RDSGEIS does not indicate what they would be.

Issue 2 Recommendations

It is presumed the alpha emitters were analyzed by alpha spectrometry, but the RDSGEIS should confirm this. The RDSGEIS also needs to provide reporting limits for the other analytes, not just provide a list of the analytes to be measured. An analysis for arsenic is useless if the reporting limit is 50 ppb when the drinking water standard is 10 ppb.

Documentation of the method is particularly important for the gross alpha analysis. EPA Method 900.0 for gross alpha allows samples to be composited quarterly and allowed to sit for up to a year before analysis. Unfortunately, the EPA approved analytical method can allow more than 60% of the ^{210}Po in a sample to be lost due to decay during that year (Seiler et al., 2011). A simple statement that Method 900.0 will be followed is inadequate. The RDSGEIS should explicitly state that samples for gross alpha will not be composited and must be analyzed within 3 days of sample collection. Analysis within 3 days is SOP for many agencies and finding labs that can meet that requirement should not be a problem.

Issue 3.

Radon in Natural Gas

Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. Burning of natural gas in stoves, water heaters, and furnaces does not affect the radioactivity of radon and consumers will be potentially exposed to increased levels of atmospheric radon.

The RDSGEIS does not include measurements of radon concentrations in the natural gas, nor does it indicate plans to monitor it. Radon concentrations in natural gas are extremely variable and can be very high. Natural gas from Texas and Kansas had radon concentrations ranging between about 5 and 1500 pCi/L (Dixon 2001,

Table 2). This raises the possibility that radon concentrations in gas from the Marcellus Shale could be much higher values than are in the gas currently being used. In addition, the hydraulic fracturing process would be designed to maximize extraction of natural gas from the formation, and as a consequence may also maximize extraction of radon from the formation.

The pipeline from well heads tapping the Marcellus Shale will be much shorter than the existing 1500 mile pipeline delivering gas from Texas/Louisiana. Assuming the gas moves through the pipeline at 10 mph, it would take 6.25 days for gas from the wellhead to the consumer, and during this time ~68 percent of the radon will decay. If wellheads in the Marcellus Shale are only 100 miles from the consumer then only 7 percent of the radon would have decayed. Because of this, even if the wellhead radon concentrations in gas from the Marcellus Shale were identical to those of the currently used natural gas, consumers would be exposed to greater radon concentrations because the wellheads are closer.

Dixon (2001) provided a risk assessment for the radon in natural gas in the UK. The average radon in natural gas from the UK wells was 5.4 pCi/L, and, as a worst-case scenario, Dixon (2001) assumed that there was instantaneous delivery of the gas so that no radon decay occurred between the wellhead and the consumer. Dixon (2001) concluded there was negligible risk to the public from release of radon in combustion gasses, and that the average dose to the public using 100 cubic meters of gas would be only 4 microSieverts per year (μSv/yr). The greatest risk was to workers in large commercial kitchens who would receive a dose of 19 μSv/yr.

Issue 3 Recommendations

The risk to the public from radon in the natural gas probably is small. Measurements of radon in the gas are needed, however, to confirm that radon levels in the gas are within the expected range. A new risk assessment should be made using actual measurements of radon in gas from the Marcellus Shale and other factors specific to New York, such as the background radon concentration for the area. For

a worst-case scenario the assumption should be made that there is instantaneous delivery of gas from the wellhead to the consumer.

Issue 4.

^{210}Po Buildup in Delivery Pipes

On page 6-205 of the RDSGEIS there is a discussion of scale buildup in pipes and equipment, but the discussion seems to indicate Ra is the principle radionuclide of concern. If radon, ^{210}Pb or ^{210}Po are present at high concentrations in the water or gas, a more significant health risk for workers could be ^{210}Po in the scale. Summerlin and Prichard (1985) evaluated this and concluded that workers cleaning impellers could be exposed to high levels of atmospheric ^{210}Po.

Consumers and State and Local workers may also be exposed to ^{210}Po, which will form in scale on all pipes carrying natural gas with radon in it. The amount of ^{210}Po buildup will depend on the amount of radon in the gas. Plumbers and City/State employees working on the pipes may not know what precautions need to be taken, and thus could be exposed to ^{210}Po in the scale.

Another issue is the volatility of ^{210}Po, which is completely volatile at temperatures above 500^{o}C (Radford and Hunt, 1964). Because of this, ^{210}Po that accumulates near burners that have been turned off may be vaporized when burners are turned on. This could potentially expose consumers to health risks from inhaling ^{210}Po. In cases of accidents or fires involving gas lines, first responders and the public near the incident could also be exposed to ^{210}Po through inhalation. This risk is not specific to gas from the Marcellus Shale. The health risks, however, would be related to the amount of radon in the gas and thus the amount of ^{210}Po that would build up, and this is not known for gas from the Marcellus Shale.

Issue 4 Recommendations

Measurements of radon in natural gas from the Marcellus Shale need to be made. A risk assessment should be made for inhalation of ^{210}Po resulting from scale buildup in delivery pipes.

Issue 5.

^{210}Po drinking-water standards

Table 2-3 presents drinking water standards for radionuclides. The US does not have a standard specifically for ^{210}Po largely because ^{210}Po is extraordinarily rare in drinking water. The US standard for ^{210}Po is exceeded if the gross alpha minus the U activity exceeds 15 pCi/L. Canada and the European Union have set drinking-water standards specific for ^{210}Po at 5.4 and 2.7 pCi/L, respectively (Health Canada, 2007; Commission of the European Communities, 2001). The regulatory use of the gross alpha standard assumes it will adequately identify samples with ^{210}Po levels that exceed health safety standards. For several reasons related to Po chemistry and the gross alpha analytical method, this may not be the case (e.g. Seiler, 2011).

Item 5 Recommendations

For any analysis where there may be actual human exposure, the RSDGEIS should analyze ^{210}Po analyses using alpha spectrometry rather than using gross-alpha analyses as an inexpensive but inadequate surrogate.

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Attachment 5

Susan Christopherson, Ph.D.

Memorandum

To: Kate Sinding, Natural Resources Defense Council

From: Susan Christopherson, Ph.D.

Date: January 11, 2012

This memorandum comments on issues in the sections of the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) and accompanying documents that address the social and economic impacts of natural gas development using high volume hydraulic fracturing (HVHF) proposed for New York, and evaluates the sufficiency of the impact analysis presented and the mitigation measures identified. HVHF describes a stage in the gas extraction process whereby large amounts of water, toxic chemicals, and sand are injected at high pressure to create fissures in low-permeability formations and thereby allow the release of gas. The process is capital intensive, and throughout its duration, poses significant environmental risks. The New York State Department of Environmental Conservation (NYSDEC or the Department) is charged with identifying and evaluating the impacts of gas development using HVHF, including both the benefits and the costs that will be borne by the communities and counties where drilling will occur.

In preparing these comments, the key documents reviewed include:

- The 2009 scope of work for the SGEIS.
- Comments prepared by AKRF and other technical experts on the 2009 draft SGEIS.
- A report prepared by Sammons, Dutton and Blankenship (2010) in response to comments on the 2009 draft SGEIS analysis of socio-economic impacts.
- The RDSGEIS released in September 2011 and particularly sections addressing socioeconomic and community impacts (6.8 and 6.12) and mitigation (7.0).
- The Economic Assessment Report (EAR) prepared by Environment and Ecology LLC to accompany the RDSGEIS.

These comments also draw on my own research on input/output models and community impacts and on research that has been conducted on the social and economic impacts of natural gas drilling in shale gas plays across the United States. Other documents cited in these comments are included in the reference list.

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. These comments identify areas of social and economic impact that require additional or revised research or analysis in the SGEIS. Overall, the discussion of social and economic impacts in the RDSGEIS is poorly organized. Social and economic topics are discussed in several sections of the RDSGEIS and statements are made in some sections that are contradicted by evidence in others. The differences between the social and economic impacts of vertical and horizontal drilling are not addressed in a systematic way. Critical assumptions underlying the socioeconomic

impact analysis were accepted from industry sources (the Independent Oil and Gas Association of New York or IOGA NY) without independent verification.

Substantive concerns include the following:

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a "ramp-up" period and then proceeding through a regular pattern of well development over time. Experience from shale plays in the Western United States demonstrates that volatility and unpredictability are intrinsic to natural gas extraction, as operating companies assess their commercial options from one shale play to another or within one shale play and allocate rigs to respond to those options. The model used in the RDSGEIS is misleading, giving the impression that communities in the drilling regions will experience economic disruption only once, during a ramp-up phase, rather than periodically, as operating companies repeatedly enter and leave the region. The problems with the model are then compounded, as projected impacts on population, jobs, and housing are predicated on one-time ramp-up and adjustment phases rather than on a process in which rigs may move in, move out, and move in again, in an unpredictable sequence. Because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model used in the RDSGEIS cannot appropriately assess those impacts. The limitations of the model should have been explained with reference to the literature that describes the irregular, unpredictable course of natural gas development, including rig movement among shale plays and the frequency of re-fracturing wells.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required along with an estimate of how costs will increase and accumulate as development expands. Although some of the potential community character and economic costs associated with the projected drilling scenarios are mentioned in the RDSGEIS, there is no attempt to quantify those costs to the state or localities either as part of the modeling process or separately.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur. For example, NYSDEC proposes to ask operators to identify inconsistencies with local zoning and other comprehensive land use planning, but there is no explanation of how the inconsistencies will be addressed in the permitting process or regulatory system. All mechanisms that will be relied on to address adverse social

and economic impacts need to be defined and incorporated into enforceable mitigation measures.

Part I of these comments focuses on the socioeconomic impact analysis in section 6.8 of the RDSGEIS. Section 6.8 adopts the assumptions utilized in the EAR and summarizes its more detailed description of anticipated impacts from HVHF gas development. Part I.A pays particular attention to the model employed in the EAR and its assumptions about how the exploratory, drilling, production, and resource depletion phases of development will occur. These assumptions do not adequately consider the uncertainties and risks associated with HVHF gas development. Part I.B comments on particular issues and areas of impact addressed in the RDSGEIS. Part II discusses issues pertaining to the distribution of economic benefits that are raised by the EAR but not addressed in the RDSGEIS. Part III comments on the mitigation proposed for potentially significant social and economic impacts.

I. NYSDEC's Socioeconomic Impact Analysis

A. The Unpredictability of Natural Gas Production and How It Is Treated in the RDSGEIS

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the amount of commercially extractable gas from any particular well is uncertain. Because of the speculative nature of the industry, there are significant economic risks associated with natural gas production. These risks are magnified by the costs involved in natural gas development, which uses capital-intensive technologies such as those engaged in hydraulic fracturing.

The industry is organized in such a way that these risks can be lessened. For example, a limited number of rigs is available nationally, and they are deployed among and within natural gas plays based on calculations of well productivity and commercial return. The drilling labor force is not fixed to a place, but moves with the rigs based on operator company strategies. Work is carried out by contractors on a project-by-project basis to maximize flexibility and efficient deployment of the specialized skills needed.

Because of the speculative character of commercial development of natural gas plays, there are uncertainties in how any shale gas play or portion of a play will be developed. What this means in practical terms is that the regions where shale gas development occurs can experience considerable volatility in the timing of well development and in the scale of well development (in the total number of wells). This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, regions may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies (Best, 2009; Headwaters Economics, 2011; Jacquet, 2009; Sammons, Dutton and Blankenship, 2010).

The EAR does recognize both production volatility and price volatility in the gas industry. In describing national drilling activity, the authors report: "The number of active gas

drilling rigs fluctuated substantially over the decade, with the number of rigs in the most active quarter being 2.35 times the number in the least active quarter." (EAR, 2-2). In New York, "the average wellhead price for natural gas remained at relatively low levels in the 1990s, generally increased thereafter, reaching a peak in 2008, and then fell sharply in 2009." (EAR, 3-12).

The EAR also briefly mentions the difficulties that the unpredictability and volatility of natural gas development presents for predicting social and economic impacts (e.g., EAR, 4-59, 4-111). The model used to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable.

The RDSGEIS mentions the uncertainty and variation in well productivity in sections not addressing socioeconomic impacts (RDSGEIS, 2-5, 2-62, 2-74, 4-17). However, the section of the RDSGEIS that specifically addresses socioeconomic impacts (Section 6.8) ignores the evidence of unpredictability in the pace and scale (timing and total well development) of natural gas development from New York counties with vertical well development and from other shale plays. Instead, it reports results from the model used in the EAR to project social and economic impacts from HVHF gas development that assume a regular, incremental, and predictable pattern of well development and production over a 60-year period, both on a statewide basis in three defined regions and under two development scenarios (low and average). Like the EAR, the RDSGEIS neglects the implications of variable well productivity and commercial viability -- critical considerations that will affect the pace and scale of drilling as well as its geographic distribution.

A1. Uncertainties Regarding Well Productivity

The RDSGEIS and accompanying EAR do not meaningfully recognize a central category of uncertainties that will affect the pace and scale of drilling – the uncertainties surrounding well productivity. Instead, NYSDEC states with respect to the low and average development scenarios analyzed:

> Both development scenarios assume a consistent timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year ramp-up period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end.

(RDSGEIS, 6-209).

This approach is one of the major weaknesses of the RDSGEIS because the assumptions of a 30-year well production cycle and a sub-regionally consistent roll-out of wells that will move through the drilling and production phases over 60 years are not supported by evidence from other shale plays. In fact, there is sufficient evidence of precipitous declines in well productivity and the costs of HVHF gas development relative to ultimate recovery to raise questions about why the 30-year development/60-year productivity profile was adopted (Berman, 2010; Berman and Pittinger, 2011; Hughes,

2011; Urbina, 2011). In an analysis of shale gas wells across shale plays, Berman and Pittinger (2011) found thousands of wells that dropped below commercially viable production between 5 and 12 years after initial drilling. The average commercial life of these wells was 8 years. NYSDEC should not have used data provided only by IOGA to construct the roll-out model; rather, it should have obtained evidence and data from independent sources who do not stand to benefit from the projection of long-term, predictable resource development.

Another example of questionable assumptions that likely over-estimate potential gas extraction from the New York portion of the Marcellus Shale is the well productivity projections used in the EAR. These are presented in Tables 4-3, 4-4 and 4-5 of the EAR. Although ultimate recovery figures are not presented in the EAR, they can be calculated based on the yearly production projections presented in 4.1.3 and the number of wells projected in 4.1.2.

These productivity projections are considerably higher than the well productivity results from existing shale plays found by Berman and Pittinger (2011). In addition, calculations of well productivity over the 60 year period produce ultimate recovery figures for the New York portion of the shale play that, in the medium and high scenarios, exceed most scientific estimates of ultimate recovery (Coleman et al, 2011). Although the 29 Tcf low scenario (for 60 years) does not exceed geologist Terry Engelder's estimate for New York's portion of the Marcellus shale, the productivity projections seem particularly questionable considering that, "The Marcellus fairway in New York is expected to have less formation thickness, and because there has not been horizontal Marcellus drilling to date in New York the reservoir characteristics and production performance are unknown. IOGA-NY expects lower average production rates in New York than in Pennsylvania." (RDSGEIS, 5-139).

Moreover, as pointed out by a group of economists commenting on the EAR assumptions and methods (Barth, Kokkelenberg and Mount, 2011), the range of estimates of productivity is so large as to be meaningless. For example, estimates for well productivity during the 23rd year of production range from 600 billion to 3.6 trillion cubic feet, a variation on the order of 600%. Accuracy in these estimates is critical to derive estimates of tax and employment effects. As it stands, the estimates used in the EAR are no better than bloated "guesstimates."

The use of IOGA's estimates as the sole source of well productivity projections undermines the credibility and accuracy of the EAR and the RDSGEIS. The estimates of well productivity must be revised to more accurately reflect expert opinion on anticipated well productivity in the New York portion of the Marcellus shale. In addition, the RDSGEIS must be updated to reflect the Energy Information Administration's revised estimates of natural gas in the Marcellus shale based on the USGS analysis (Coleman et al, 2011).

The uncertainties associated with the productivity of extraction from the Utica shale must also be addressed, if Utica shale wells are to be included in the SGEIS analysis. In the EAR, the projections for the number of wells to be drilled include those for the Utica shale. There are significant uncertainties about the productivity of that play, the geographic variation in liquid content across that play, whether the well spacing and fracture treatment would resemble those for the Marcellus, and what technologies would be used in Utica shale development (Yost, 2011). These unknowns are significant and

indicate that Utica shale development may proceed differently than Marcellus shale development and utilize different technologies.

The unspecified inclusion of well numbers and productivity figures from the Utica shale also raises questions about the extrapolated employment, housing and tax implications that are attributed to Marcellus shale development.

The issues surrounding productivity are further complicated by the common practice of re-fracturing wells to increase pressure and productivity. If re-fracturing is practiced in New York Marcellus wells, communities will be repeatedly subjected to the environmental disruptions associated with heavy industry.

The uncertainties around and questions raised about long-term well productivity argue for modeling a shorter-term development and production cycle. At the very least, the competing evidence concerning well productivity and the cost of recovery should have been discussed in the RDSGEIS to qualify assumptions concerning the production cycle and estimated ultimate recovery.

A2. Impacts of the Uncertainties Associated with HVHF Gas Development

Evidence from Western shale plays indicates that the volatile pace and scale of natural gas development drives many environmental and social and economic impacts (Best, 2009; Jacquet, 2009; Headwaters Economics, 2010). Impacts directly affected by the pace and scale of drilling include:

1) Labor force needs and behavior. (How much of the workforce remains transient rather than becoming local? A local labor supply cannot develop if gas development is unpredictable.)
2) Demands placed on public services, including health facilities, public safety, and schools. (Can communities adapt over time or are there unpredictable rises and falls in demand?)
3) Community character impacts from increases in traffic, noise, construction disruption, and the transient population. (Do these increases roll out in a regular fashion with the expectation that disruptive “ramp-up” will end or are they unpredictable over a long period of time?)
4) Impacts on rural industries, such as tourism. (Can the scale of noise and traffic be predicted to occur only for a short period or are disruptive activities likely to recur over a longer period of time, for example, with re-fracturing of wells?)
5) Housing demand and cost. (Will there be periodic housing shortages with homelessness and lack of affordable housing for people on fixed incomes, potentially followed by excess housing supply and falling home values?)

To illustrate: As well pad construction begins in an area, jobs increase along with housing construction and business development. A transient population (in addition to transient industry workers) migrates to the area because of the prospect of jobs, increasing the demand for housing and services, including education and health. For a variety of reasons (price of natural gas, availability of higher value opportunities elsewhere, rig availability), natural gas development may drop off in the area within five-ten years of this initial “ramp-up.” Evidence from gas plays in Western states indicates that this drop-off may be sudden. In the wake of this drop in production and the number

of drilling rigs in the area, the transient population leaves and resident communities are left without jobs and revenue. Local governments may still be paying the public costs of ramping up to respond to the initial "boom." If conditions change (rigs become available, prices rise), the rigs may return to the area, causing another production "boom" with all of its attendant costs.

This pattern is described by Spelman (2009) and is associated with a reluctance of business (other than the gas industry) to invest in regions characterized by boom-bust economies. A contemporary example of such reluctance is contributing to the housing crisis in the Williston North Dakota Bakken Shale development. According to interviews conducted there: "Developers have been slow to build more apartments, largely because they got stung by the region's last oil boom that went bust in the 1980s." (MacPherson, 2011).

This volatile pattern is dramatically different from the scenario presented in the EAR and RDSGEIS. In both documents, communities are assumed to be impacted by a boom only once (during "ramp-up") and are gradually able to adjust to natural gas drilling. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this gradual, regular development scenario. For example, the RDSGEIS assumes that as the industry "matures" in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals. The RDSGEIS's use of a model built around regular, predictable development of the shale gas resource raises doubts about the projection of economic benefits based on that model.

A3. Hot Spots, Socioeconomic Impacts, and Public Costs

Contrary to the contention that the regularized development model "does not significantly affect the socioeconomic analysis" (RDSGEIS, 6-209), smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. The RDSGEIS admits that steady, constant well construction is "unlikely" (RDSGEIS, 6-209), but it fails to analyze the implications of this admission and offers no description or evaluation of the adverse impacts of temporally and spatially uneven development.

In contrast with the model used in the RDSGEIS, natural gas development does not resemble a "manufacturing" process. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. Well productivity may be uniformly low across a region, or there may be long-term well productivity in particular "hot-spots." The question of how many wells will exhibit long-term productivity and where they will be located is unknown before exploratory drilling takes place and, even then, well productivity will be unpredictable.

The RDSGEIS admits that its socioeconomic analysis is based on average well productivity (RDSGEIS, 6-210), but the production process in natural gas (pace and scale) is not effectively captured using averages. The uncertainties in the geographic extent of drilling and the potential for intensive development in "hot spots" have

implications for social and economic impacts. For example, if drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape for 60 years (as is modeled in the RDSGEIS and EAR), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic costs of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry. There is no attempt to address this likely unbalanced distribution of positive and negative impacts in the RDSGEIS.

Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies. Figure 6.13 (RDSGEIS, 6-215) shows the drop in direct and indirect employment following resource depletion. This depiction needs to be accompanied by analyses of how the resource depletion phase will be reflected in royalty payments and tax revenues.

A4. Socioeconomic Impact Analysis Can Accommodate the Uncertain Pace and Scale of Gas Development

If the impacts of volatility are to be mitigated, their prevalence in natural gas extraction regions needs to be acknowledged in the SGEIS. It is difficult to model the unpredictable pace and scale of natural gas production, but that difficulty is no excuse for ignoring adverse social and economic impacts arising from volatile and unpredictable development. Those impacts have been documented in relation to the phases of exploration, construction and drilling, production, and resource depletion, recognizing the company strategies that produce economic volatility in resource extraction regions (Jacquet, 2009; Kelsey, 2009; Sammons, Dutton and Blankenship, 2010).[1]

In cases where it is not possible to model specific cause-effect relationships (such as the relationship between well development and public costs), but where there is evidence of potential adverse impacts, those impacts should be recognized and documented. Sammons, Dutton and Blankenship (2010) take this approach in their report

[1] From Sammons, Dutton and Blankenship (2010):

> Several recent studies address (social and economic) aspects of natural gas development in the western U.S. They include the *Northwest Colorado Socioeconomic Analysis and Forecasts* prepared for the Associated Governments of Northwest Colorado and the *Sublette County Socioeconomic Impact Study: Phase I Final Report* and *Phase II Final Report,* prepared for the Sublette County, Wyoming Board of County Commissioners. A third report, the *ExxonMobil Piceance Development Project Environmental Assessment - Socioeconomic Technical Report,* prepared by the authors for the U.S. Bureau of Land Management White River Field Office, assesses potential effects of a specific natural gas project in the context of ongoing large scale natural gas development in northeastern Colorado. A more recent journal article, *Energy Boomtowns & Natural Gas: Implications for Marcellus Shale Local Governments & Rural Communities,* published by the Northeast Regional Center for Rural Development, describes a model for impact assessment, presents a case study describing Sublette County's experience with large scale natural gas development and discusses some possible implications for Marcellus Shale development.

commissioned by the New York State Energy Research and Development Authority (NYSERDA) to describe socioeconomic impacts that can be anticipated with HVHF gas development. In addition, NYSDEC needs to quantify known social and economic costs even if their occurrence cannot be synchronized with their scenario model of development. This quantification can be accomplished through examination of comparable cases of impact, a standard method used in fiscal impact analysis (Kotval and Mullin, 2006).

B. NYSDEC's Analysis of Specific Socioeconomic Impacts: Model Assumptions and the Use of Representative Regions

The RDSGEIS presents only a fraction of the material contained in the EAR and acknowledges: "A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this RDSGEIS." (RDSGEIS, 6-207). This section identifies questions and concerns regarding the assumptions underlying the model used to predict impacts of HVHF development in New York State. These comments focus particularly on the use of representative regions to project impacts throughout New York State, including those for Utica shale gas drilling.

B1. The Use of Representative Regions

NYSDEC's use of a set of Southern Tier counties to represent all counties in New York that may experience HVHF shale gas drilling (EAR, 6-217) raises concerns about the representativeness of these counties. The EAR and RDSGEIS define three representative regions for the socioeconomic analysis, with Region A representing counties accounting for a high percentage of overall well development, Region B representing counties with about half the development of Region A, and Region C representing counties not expected to have much production but with a history of drilling. In the RDSGEIS, characteristics from a representative region are used to make assumptions about socioeconomic impacts in other New York State regions where drilling may occur. For example, tourism impacts are assumed to be minimal for all regions based on the continued presence of a tourism industry in Region C. The EAR and NYSDEC need to provide evidence (in industrial composition, growth rates, and population composition) to support the assumption that these counties are "representative" of all the counties that may experience drilling.

In addition, the EAR indicates that it addresses "local" impacts, but there is no analysis below the county scale. Analysis of differential economic impacts in urban and rural areas, for example, is critical to understanding the total economic impact picture. For example, counties in Region A in the EAR scenario analysis include both urban areas such as the Binghamton Metropolitan Statistical Area and rural areas where tourism and agriculture are the primary industries. Urban areas will garner more expenditures from natural gas drilling in the region, but are also likely to have negative impacts in the form of increased crime and demand for health services (because of their location in the urban areas). Rural areas will experience intense impacts on their small rural communities, including demand for housing and increases in road damage, as well as potential negative effects on agriculture and tourism. These local impacts, and how the costs and benefits will be distributed, need to be assessed separately.

B2. The Use of a RIMS Input-Output Model to Assess Social and Economic Impacts

A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model developed by The Bureau of Economic Analysis. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF or tell us anything about fiscal impacts.

The purpose of the model is to deduce direct and indirect economic impacts of new expenditures in a region. This type of model is very limited in the types of impacts it can assess. It is typically used to estimate some economic impacts, but is not useful to assess the wide range of social impacts that have been identified as occurring with HVHF shale gas drilling. So, for example, the model can be used to derive population increases and then, to crudely extrapolate potential housing demand. It cannot tell policy makers anything about the impact of housing demand on different population segments or on community character.

The results of this kind of model will always be positive because the model begins with the inflow of expenditures in the region. If the modelers had examined new expenditures flowing into the region's tourism or agricultural sectors those, too, would be positive. The model provided in the RDSGEIS does not allow us to assess opportunity costs, that is, to compare the economic impacts of shale gas drilling with those that might occur with increased investments and expenditures in other industries. This is important not only because shale gas drilling impacts are being considered in "isolation," but because investments in industries such as tourism and agriculture might decrease because of "crowding out" by HVHF activity (Christopherson and Rightor, 2011)

A model of this type is completely dependent on assumptions about the source of expenditures in the region. For example, in the case of HVHF gas development, the model is based on assumptions such as those about where the labor force hired in the drilling phase will spend the money they earn -- in the drilling region or in their home states? These assumptions are critical to the model results and should have been made available so that the accuracy of the model could be analyzed.

The presentation of the model results in the EAR is neither useful nor informative. Much of the text is devoted to tables that present mechanical calculations. These tables should have been relegated to an appendix and the body of the report used to lay out and support the assumptions that underlie the calculations.

In December 2011, the consulting firm that developed the EAR was asked to evaluate costs associated with gas development using HVHF in New York State. Because the RIMS input-output model and the associated scenario approach cannot address the costs of such development, the use of this approach rather than one that addresses costs as well as benefits needs to be justified and re-visited. In addition, because of its inability to address costs, the model does not provide information on impacts that require mitigation. Given the inadequacies of the EAR model and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings

regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

C. NYSDEC Analysis of Selected Social and Economic Impacts

This section comments on section 6.8 of the RDSGEIS, which assesses a selective subset of the many social and economic impacts anticipated with HVHF natural gas drilling. These include: (1) economy and employment, (2) population, (3) housing, (4) government revenue and expenditure, and (5) environmental justice. This section concludes with comments on material presented in the EAR that is not discussed in section 6.8, but which is relevant to the RDSGEIS findings regarding social and economic impacts.

C1. Economy and Employment

Employment. The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs) (Jacquet, 2009). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment) (EAR, 3-7). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells (EAR, 3-31).

The employment multiplier projected for New York State (2.1766) (derived from the model used in the EAR) is exceptionally high, especially for investment from a capital-intensive industry. (A 2.0 multiplier is considered generous by most regional economic analysts.) This underscores the importance of making the assumptions underlying the model transparent. For example, is the basis for the multiplier used an assumption that expenditures on real estate development resulting from the HVHF gas development will accrue disproportionately to New York state firms? If so, why? Because unrealistic and overly optimistic assumptions made in constructing the models may overstate economic benefits, assumptions underlying this RIMS model need to be available for scrutiny.

Finally, the employment figures presented in Table 4-8 are "full–time-equivalent" (FTE) jobs. These jobs do not correspond with what the ordinary person thinks of as a job – a person employed full-time to carry out certain tasks. They are a composite of part-time and full-time jobs that might be developed from the 410 job activities associated with constructing and drilling a well and from the subsequent production phase. These may not be new jobs, but existing jobs required to sustain industry activity. Finally, the EAR does not provide sufficient context for evaluating the employment impact of gas development using HVHF in the state. Projected employment in HVHF development should be compared with that in other New York industries, including tourism, to place the numbers in perspective. Projected increases in employment in these other

industries should be provided to enable comparison and to estimate costs and benefits of permitting HVHF gas development.

Impacts on other regional Industries. Having described in detail the modeled economic and employment growth from the gas industry, the RDSGEIS then mentions the potential adverse impacts on existing industries in the regions where natural gas development will occur. In a bare two paragraphs, the RDSGEIS admits:

> Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the [sic] natural gas drilling and production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.
>
> Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry.

(RDSGEIS, 6-230).

In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine state investments intended to support those industries. As discussed in detail below, given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

Tourism. The RDSGEIS makes no effort to quantify the value of tourist activities that may be adversely affected by gas development but rather dismisses any impacts as insignificant.

Nearly 674,000 New York jobs were sustained by tourism activity last year, representing 7.9% of New York State employment, either directly or indirectly. New York State

tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010.

Tourism in the Southern Tier counties includes a wide range of activities, from visits to the Corning Glass Museum to hiking, hunting, and fishing in the rural areas. The Southern Tier Central (STC) Planning District, which includes Chemung, one "fairway" county (where significant natural gas drilling is anticipated because of the geologic formation) located in Region A in the RDSGEIS analysis, has published a study indicating that:

> In 2008, visitors spent more than $239 million in the STC region across a diverse range of sectors. The tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in the STC region that year. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue -- a tax benefit of $1,181 per household.

(Rumbach, 2011, page 1).

Tourism is thus a significant contributor to the counties in New York potentially impacted by HVHF gas development. The tourist opportunities and activities also contribute to the quality of life of local residents and attract companies in other sectors, such as manufacturing.

NYSDEC's use of Chautauqua and Cattaraugus Counties as the basis for contending that tourism will not be significantly impacted in New York is not persuasive. First, the evidence offered for the judgment that those counties have "healthy tourism sectors" (RDSGEIS, 6-231) consists of nothing more than the statement that: "In 2009 wages earned by persons employed in the travel and tourism sector in Chautauqua and Cattaraugus counties (Region C) were approximately $77.5 million, or about 3.0% of all wages earned in Region C" (NYSDOL 2009b*)* (see Table 3-37)" (EAR, 3-27). Without comparing Chautauqua and Cattaraugus over time with similar counties where natural gas development has not taken place, it is impossible to determine whether the tourism sector of the Region C counties has been negatively impacted by shale gas drilling.

The contention that those counties represent a tourism success story is contradicted by data presented in the EAR, which shows that from 2007 to 2009, Region C tourism employment declined 17%, and wages declined 13% (EAR, 3-28). While a portion of this decline might be attributable to the recession, there is no justification for describing waning tourism in the region as "healthy."

In addition, there is growing evidence regarding the negative effects of shale gas drilling on tourism in the counties where shale gas drilling takes place (Rumbach, 2011).

> Evidence from other shale plays in the Western U.S. indicates that natural habitat tourism (whether hunting, fishing, birding or hiking) may be disrupted for long periods of time and in some cases where infrastructure, such as compressor plants and pipelines, disrupts habitats, may be permanently altered.

(Sammons, Dutton and Blankenship, 2010). Negative impacts derive not only from the loss of habitat for outdoor sports, but also from the "crowding out" of tourism activities (because of increasing prices in the drilling region and the loss of hotel spaces to gas industry workers) and from the impact of regional industrialization on the tourism brand. For example, tourism centers in Upstate New York, such as the Finger Lakes wineries, may experience losses when tourists looking for a rural retreat find themselves driving through an industrial region with heavy truck traffic and shift their allegiance to quieter and more accessible vacation spots. In addition, the RDSGEIS does not assess the impacts on tourism from degradation of historical and cultural assets.

The EAR also conflates access to private recreational land for purposes of hiking, hunting, and fishing with the success of commercial tourism businesses. The relationship between personal recreational opportunities and natural gas development is presented as one of personal trade-offs in terms of land use. The negative impacts on the options of non-land owning recreationists are mentioned but not addressed (EAR, 4.58).

Rumbach's assessment of HVHF gas development on tourism is that:

> ….individual impacts are unlikely to have serious and long-term consequences, but without mitigation, cumulatively they could do substantial damage to the tourism sector. Examples of such impacts include strains on the available supply and pricing of hotel/motel rooms, shortfalls in the collection of room (occupancy) taxes, visual impacts (including wells, drilling pads, compressor stations, equipment depots, etc.), vastly increased truck and vehicle traffic, potential degradation of waterways, forests and open space, and strains on the labor supply that the tourism sector draws from. All told, the region's ability to attract tourists could be damaged in the long-term if the perception of the region as an industrial landscape outlasts the employment and monetary benefits of gas drilling.

(Rumbach, 2011, page 2).

The RDSGEIS fails to address the long-term costs associated with displacing business in existing industries, such as tourism, that provide economic diversity in the regional economy and thus increase its prospects for sustainability.

Agriculture. Potential negative impacts on agricultural production and land use are noted, but their impact is not assessed nor are any mitigation measures proposed (RDSGEIS, 6-231). There is no analysis of whether and how HVHF gas development will affect sub-sectors of agriculture, such as dairy farming, which are of key importance in the New York economy.

Milk and other dairy products account for more than half the total value of agricultural products sold in New York State, accounting for $2.2 billion in receipts in 2010. According to the US Department of Agriculture, New York ranks third in the US in production and sale of dairy products. Certainly the size and importance of this industry to the New York economy warrants a full analysis of how production and producers will be impacted by HVHF gas development. Instead, the RDSGEIS lacks an economic

assessment of how temporary and long-term agricultural costs and productivity will be affected by HVHF development.

Recent evidence from Pennsylvania indicates that agriculture and particularly dairy farming may be significantly affected by drilling activity. For example: "(Bradford) county's dairy herd has decreased over the last decade from 30,000 head in 2002 to just under 20,000 head today. Another 15 dairies have been sold since the beginning of the year (2011)" (Tomes, 2011). Although evidence from Pennsylvania is anecdotal, there is sufficient information to indicate that one of New York's major industries will be negatively affected by HVHF gas drilling.

Dairy farms are decreasing in areas with natural gas development both because some farmers have another source of income and because costs for dairy farmers are going up as a consequence of the impact of the drilling economy in the county. For example, competition for truck drivers is raising the cost for dairy farmers to transport their milk to processors. In addition to the impacts on the dairy farms themselves, the infrastructure that supports dairy farming in Bradford County is being affected. For example, an agricultural equipment dealer in the County has gone out of business because of an inability to hire and retain a workforce (Tomes, 2011).

There are also land use impacts that affect farmers, including impacts not only from the well pads, but also from the ancillary industrial facilities, such as "laydown yards" (operations and storage sites), pipelines, and compressor stations (Tomes, 2011).

The American Farmland Trust (2011) has submitted comments on the RDSGEIS that summarize its expert assessment of the impact on agricultural production in New York State:

> …the DEC's analysis of the impacts of drilling and hydraulic fracturing to agricultural land is inadequate and encourages specific analysis of the likely impacts of such activities to agricultural land resources. The SGEIS analysis should consider the scale of farmland likely to be converted by both direct drilling activities and the off-site drilling support services and other types of residential and commercial development that is anticipated as a result of natural gas drilling. In addition, it should consider the impacts of such activities to agricultural land values and on the ability of New York farmers to maintain their competitiveness in a global economy.

Upstate New York is currently experiencing a resurgence in its food processing industry, and the State Agricultural and Markets Program has a stated policy of encouraging more dairy production in the state. In July 2011, the State of New York provided $16 million in incentives to a dairy processing company in Chenango County in Central New York. According to a statement by Governor Cuomo: "Agro Farma's expansion in Chenango County will create hundreds of new jobs and increase the demand for milk from New York dairy farms," (press release available at: http://www.governor.ny.gov/press/07212011DairyProductsCompany).

The support from New York's Empire State Development Corporation reflects the significance of this industry to the regional and state economy. A full economic assessment of potential impacts to this industry is warranted. This assessment should include labor costs (from competition for truckers, for example) and impacts on specialty

agricultural producers, such as organic farmers. New York State has the fourth largest number of organic farms in the U.S.

The Finger Lakes wineries, combining agriculture and tourism, are another important subset of New York industries that may also be affected by HVHF gas development in Upstate New York. New York State ranks third nationally in grape production. Tourists visiting the wineries may not want to drive through industrial development and its associated truck traffic in order the reach the wineries, even if the wineries are not locally impacted by the drilling process. Given the importance of this and other sectors of New York's agricultural industry to the Upstate New York "brand" and the investment of State resources to build the industry, the SGEIS needs to separately assess the impacts on this industry and develop mitigation policies to address the negative impacts identified.

Manufacturing. Finally, the RDSGEIS and the EAR focus exclusively on impacts to agriculture and tourism because the use of land by those industries potentially competes with use of land for gas development. Focusing on that competition may make sense for the largely rural representative regions defined in the EAR, but it does not make sense for representative regions with more diversified economies, including substantial manufacturing. A report by the New York State Comptroller's office in 2010 shows that the Southern Tier has 14% of Upstate manufacturing. Manufacturing should be included in the assessment of impacts on existing industries, because of its significance in Region A and because gas development will affect the labor supply and industry wage rates in counties where manufacturing plays a significant role in the economy.

C2. Population

The RDSGEIS and EAR do not address population impacts on community services, such as schools and health, but only population as it relates to employment and the labor market. There was no attempt to look at actual population trends in counties with significant gas drilling and whether they reflect a decline in economic diversity that makes population levels less sustainable. An analysis of the long-term population trends in shale gas drilling counties in the US is necessary to determine the impact of HVHF gas development on New York counties. A projection based on labor demand is not sufficient.

The EAR assumes that, for the first 30 years, the population increases in counties that "host" natural gas drilling will be modest. It notes, for example:

> [A]ctual population impacts may also be less than what is described in the following section because currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

(EAR, 4-59).

By focusing only on population changes directly related to gas industry employment, the RDSGEIS avoids addressing the potential for long-term population decline beyond the loss of industry workers. Many areas with significant natural gas drilling lose population over time. That has been the case with Chautauqua and Cattaraugus counties (Region C) in New York.

In addition, the RDSGEIS assumes a gradual (rather than disruptive) integration of the unemployed population in the region and of transient workers into the labor force required by the industry. Experience from other states, however, contradicts the assumption of easy integration of the resident workforce and of newcomers to the regional labor force: "In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers" (Kelsey, 2011). The potential for a low-skilled, transient workforce to migrate into the area is not considered, although there is evidence from Western shale plays that this occurs, and is particularly likely with high national unemployment rates.

> [B]ecause labor markets are imperfect, [and] the availability of a relatively large number of jobs may result in an influx of job seekers, some of whom lack necessary skills and qualifications and may be relatively indigent. To the extent that indigent job seekers are unable to find jobs or do not have resources to secure housing and transportation to work; they can become a burden for local human service agencies. This situation can be exacerbated by weak economic conditions in other parts of the state or country.

(Sammons, Dutton and Blankenship, 2010, page 13).

The RDSGEIS fails to address this evidence of adverse economic impacts.

C3. Housing and Property Values

<u>The potential impacts on the housing supply, housing costs, and housing financing are inadequately assessed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.</u>

The report assumes that the current housing stock would be used to house any workers who move to the production region on a "permanent" (more than one year) basis (EAR, 4-107 (concluding "the impact on the supply of permanent housing units would be negligible at the statewide level during the production phase")). Given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing (Kolb and Williamson, 2011). This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the "boomtown" phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either temporarily or permanently, the value of this new housing is likely to plummet (Best, 2009).

With respect to temporary housing, the EAR (EAR, 4-111) admits:

> In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers (Kelsey 2011). There have been reports of large increases in rent in Bradford County, Pennsylvania, as a result of the influx of out-of-area workers (Lowenstein 2010). There have also been "frequent reports" of landlords not renewing leases with existing tenants in anticipation of leasing at higher rates to incoming workers, and reports of

> an increased demand for motel and hotel rooms, increased demand at RV camp sites, and increases in home sales (Kelsey 2011). Such localized increases in the demand for housing have raised concerns about the difficulties caused for existing local, low-income residents to afford housing (Kelsey 2011).

If communities add substantial temporary, short-term housing or single-family housing to accommodate development-phase workers, surplus capacity may exist in all these types of units after development is completed. Based on evidence from other shale gas plays, all of these adverse impacts (initial housing shortage, surplus supply if rigs leave temporarily and depressed value in some areas) may occur (Best, 2009; Sammons, Dutton and Blankenship, 2010).

The EAR (EAR, 4-111) also acknowledges the potential impact of the volatility of the production cycle on the housing market and property values:

> The demand for housing, both temporary and permanent, would be expected to change over time. The demand for housing would be the greatest in the period during which the wells in an areas are being developed, and demand would decline thereafter. This would create the possibility of an excess supply of such housing after the well development period (Kelsey 2011). If well development in a region occurs in some areas earlier than in others, then housing shortages and surpluses may occur at the same time in different areas within the same region.
>
> The natural gas market can be volatile, with large swings in well development activity. Downswings may cause periods of temporary housing surplus, while up-swings may exacerbate housing shortages within the regions.

A recent study of the impact of HVHF gas development in Pennsylvania indicates that impacts on the housing supply are significant, especially for people at the economic margins (Williamson and Kolb, 2011). These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% reduction in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus,

> …not all properties in the region would increase in value, as residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights (EAR, 4-114).

The EAR authors attributed the positive impact on property values of having a well located within 550 feet of a property to the prevention of further gas well development in that area due to a spacing order and setback conditions that prevented well drilling close to existing wells.

The assertion in the EAR that property owners in the drilling region would see an overall increase in property values is based on increased demand and economic activity. Evidence from Pennsylvania and from Western Shale plays indicates that this demand may not occur in the county or locality where the drilling is occurring (Patton et al, 2010).

The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values (Spelman, 2009). A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

C4. Government Revenues and Expenditures

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt (EAR, 4-116).

(2) Costs to the state that will reduce or offset tax revenues are not calculated. For an example of this problem, see the discussion of rail infrastructure in the RDSGEIS section on transportation impacts. The provision of tax rebates to railroad companies and to industry facilities represent lost revenue to the State and the locality. The EAR admits that in addition to tax benefits, "such as expensing, depletion, and depreciation deductions," which reduce taxable income, "New York State offers an investment tax credit (ITC) that could substantially reduce most, if not all, of the net income generated by these energy development companies" (EAR, 4-115 to 4-116).

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the SGEIS:

> High-volume hydraulic fracturing operations would also result in some significant negative fiscal impacts on the state. The increased truck traffic required to deliver equipment, supplies, and water and sand to the well sites would increase the rate of deterioration of the state's road system. Additional capital outlays would be required to maintain the same level of service on these roads for their projected useful life. Depending on the exact location of well pads, the state may also be required to upgrade roads and interchanges under its jurisdiction in order to handle the additional truck traffic. The potential increase in accidents and potential additional hazardous materials spills resulting from the increased truck traffic also would require additional expenditures. Finally, approval of transportation plans/permits would place additional administrative costs on the New York State Department of Transportation (EAR 4-116).

There are now numerous studies available to calculate road damage, and the counties in the "fairway" in New York State have undertaken baseline studies that would enable

accurate calculation of the costs of road damage (Randall 2011). There is plenty of expertise available in the state to draw on, including Cornell Local Roads program, which has completed a thorough analysis of the kind of damage and what it would cost to repair.

The EAR also recognizes additional public costs associated with Marcellus shale gas development:

> Additional environmental monitoring, oversight, and permitting costs would also accrue to the state. In order to protect human health and the environment, New York State would be required to spend substantial funds to review permit applications; to ensure that permit requirements were met, safe drilling techniques were used, and the best available management plans were followed; and to provide enforcement against violations. In addition, the state would experience administrative costs associated with the review of well permit applications and leasing requirements and enforcement of regulations and permit restrictions. All of these factors could result in significant added costs for the New York State government.
>
> The New York State Department of Health would also incur additional costs due to the need to provide additional technical support and oversight services to local governments that would monitor water quality in local drinking water wells (EAR, 4-116).
>
> In addition to the positive fiscal impacts discussed above, local governments would also experience some significant negative fiscal impacts as a result of the development of natural gas reserves in the low-permeability shale. As described in previous sections, the use of high-volume hydraulic-fracturing drilling techniques would increase the demand for governmental services and thus increase the total expenditures of local government entities. Additional road construction, improvement, and repair expenditures would be required as a result of the increased truck traffic that would occur. Additional expenditures on emergency services such as fire, police, and first aid would be expected as a result of the increased traffic and construction and production activities. Also, additional expenditures on public water supply systems may be required. Finally, if substantial immigration occurs in the region as a result of high-volume hydraulic fracturing operations, local governments would be required to increase expenditures on other services, such as education, housing, health and welfare, recreation, and solid waste management to serve the additional population (EAR, 4-138).

The RDSGEIS mentions public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., but makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment. Experience in other shale gas plays demonstrates that these costs are likely:

> Natural gas development and production-related activities and the incremental population associated with those activities will generate

> demand for the full range of local government facilities and services and for some state government services. For example, during exploration and moderate stages of development, demand is usually limited to law enforcement, emergency response, emergency medical and road and highway maintenance and traffic control. Traffic, vehicle and industrial accidents and issues associated with a single-status, predominately working-age male workforce are the primary drivers associated with emergency response and law enforcement increases. Because many workers are temporary, and do not have local general purpose health care providers, they commonly use hospital emergency rooms for what would be otherwise be routine health care visits.

(Sammons, Dutton and Blankenship, 2010, page 19).

This knowledge regarding public costs and fiscal impacts should have been reflected in the RDSGEIS. These costs may occur even if the amount of commercially extractable natural gas does not reach projected levels. They need to be calculated both in terms of the baseline costs that are likely to occur with any drilling activity and in relation to varying levels of drilling activity.

Addressing the variability is important because there are distinct community character impacts attributable to large-scale development that have been identified and documented in other shale plays.[2] For example:

> …some areas that experience large scale development have reported substantial increases in a variety of crime and social problems including alcohol and drug-related offenses, traffic offenses, disturbances, assaults and domestic conflicts. Although some increases in crime and social problems would be anticipated to accompany any increase in population, some researchers have also attributed the increased levels of crime and social problems to the temporary and transient nature of the workforce and their living conditions. There has been some debate in the social impact assessment literature about whether or not crime and other adverse social indicators increase at higher rates in communities experiencing large-scale development than average rates for all communities. But the implications are clear that increases in crime and social problems are likely with large-scale development, even if they are proportionate to the increase in the numbers of people working and living in affected communities.

(Sammons, Dutton, and Blankenship, 2010).

Given the scale of development being projected, the thresholds for community costs and

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[2] *See* Sublette County Socioeconomic Impact Study Phase I Final Report. Ecosystem Research Group. , January 2008. Pages 54 – 58 and Index Crimes, Arrests, and Incidents in Sublette County 1995 to 2004: Trends and Forecasts, Prepared by J. Jacquet. Sublette County, Wyoming, April 2005, *available at:* http://www.sublettewyo.com/DocumentView.aspx?DID=351; Local Social Disruption and Western Energy Development: A Critical Review, Wilkinson et.al. Pacific Sociological Review Volume 25. July 1982. *available at:* http://www.sublettewyo.com/archives/42/Local_Social_Disruption__Critical_Review_Response_and_Commentary [1]. pdf.

adaptation to the impacts related to population increase or demand for services (administrative, school, health, public safety) must be addressed by the SGEIS. Evidence from Pennsylvania indicates that ability to adapt to these community social and economic impacts is critical to short-term and long-term community well-being (Kolb and Williamson, 2011; Kelsey, 2010, 2011).

(4) Costs will vary with the nature of population increases driven by the permitting of HVHF gas development. For example, indigent job seekers unable to find jobs and without resources to secure housing or transportation to work can become a burden for local human service agencies. This situation may be exacerbated by weak economic conditions in other parts of the state or country.

An example of this phenomenon is documented in a study carried out by Guthrie Hospital/Troy Community Hospital in Bradford County, Pennsylvania, where impacts from HVHF gas development in the county have significantly increased demand for health services (Covey 2010). The hospital is treating a new non-English speaking clientele and has had to hire translators. They have also had to purchase new equipment and have experienced a significantly increased demand on their emergency room services. The new demand affects not only the bottom line of providers, but also the availability of and access to health care for residents of the region in which drilling is occurring.

(5) There is no analysis of the expected lag between immediate costs and anticipated revenues. This lag may be 2-3 years, during which communities will be faced with significant public service costs.

(6) A tax profile needs to be presented over time, not one for a single year, in order to understand how natural gas drilling has fiscally impacted Region C, where most wells are currently located and where wells have increased.

C5. Environmental Justice Impacts

A section on Environmental Justice, included at the end section 6.8 of the RDSGEIS, notes that well permits are currently exempt from screening under NYSDEC Commissioner Policy 29, Environmental Justice and Permitting (CP-29) (RDSGEIS, 6-263). NYSDEC suggests that a drilling permit applicant could, “when necessary,” conduct a GIS analysis to identify potential environmental justice areas. The RDSGEIS should set forth criteria to determine when such an analysis would be “necessary” and should include the requirement in standard permit conditions or regulations. Moreover, given the known housing impacts of gas development on low-income populations, efforts to mitigate significant adverse environmental justice impacts must include not only the “additional community outreach activities” required in the RDSGEIS, but also substantive measures to prevent dislocation and homelessness.

II. Additional Economic Impacts Identified in the EAR But Not Addressed in the RDSGEIS

The RDSGEIS presents only a fraction of the material contained in the EAR and acknowledges: “A more detailed discussion of the potential impacts, as well as the

assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS" (RDSGEIS, 6-207). This section comments on material presented in the EAR that is not discussed in section 6.8, but which is relevant to the RDSGEIS findings regarding social and economic impacts.

A. The Distribution of Impacts of HVHF Gas Development in New York State

The socioeconomic impact analysis should systematically describe the geographic distribution of impacts. In New York, as is explained below, the creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is likely to occur outside the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process (Best, 2009; Sammons, Dutton and Balnkenship, 2010). Mitigation measures need to be identified to address long-term costs to the rural counties where extraction will be concentrated.

The EAR calculates the impact of a $1 million increase in the final demand in the output of the oil and gas extraction industry on the value of the output of other industries in New York State (EAR, 3-6). The EAR then makes a series of statements concerning where the economic benefits of HVHF development are expected to occur. For example:

> The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeability shale is located. Many geological and economic factors would interact to determine the exact locations where wells would be drilled. The location of productive wells would determine the distribution of impacts.

(EAR, 4-46; emphasis added).

The location of wells is, however, only one factor affecting the distribution of economic impacts in New York State. Many wells are drilled in rural areas with no or very limited commercial services near-by. If that is the case, then the economic impacts (in the form of expenditures by drillers and companies) will not occur close to the drilling site. Some will occur in centers – perhaps across a municipal or county line – where there are stores and restaurants that the drilling company employees use for meals and supplies. Some economic impacts will occur in far away places, such as New York City, where the drilling company can buy specialized services, such as tax accounting and legal services, to meet their business needs.

This potentially broad distribution of economic impacts is reflected in the multipliers reported in the EAR as follows:

> As anticipated, the direct effect employment multiplier for the State of New York (2.1766) was substantially larger than the multipliers for the individual regions, which had direct-effect employment multipliers of 1.4977 in Region A, 1.3272 in Region B, and 1.4357 in Region C (USBEA

2011a, 2011b, 2011c, 2011d). (EAR, 4-19).

These multipliers are affected by purchases by the gas drillers from other industries in the economy. In this case, the RIMS model used in the EAR indicates that three largest industries in which purchases will be made (and additional employment created) are: (1) real estate and rental; (2) professional, scientific, and technical services; and (3) management of companies). We can anticipate that purchases from these industries would have a strong effect in New York State as a whole because these industries have a strong presence in New York State.

What the multipliers also tell us, however, is that the jobs indirectly created by purchases of goods and services by the natural gas developers are not likely to be located in the counties where HVHF gas development occurs. Multipliers tell us how strong the industry is in a region or state. Higher multipliers indicate that those businesses that the oil and gas industry is likely to purchase goods and services from are present. Lower multipliers indicate a small industry presence and thus a lower likelihood of purchases in that geographic area. So, for example, a natural gas development company would employ professional services as a consequence of expanding drilling in Chautauqua County, but is likely to go to New York City to purchase those services because they are more likely to be available in New York City. Companies providing professional services in New York City are more likely to stay there rather than move to the Southern Tier because they have more opportunities to attract diverse industries to their specialized services in New York City than in Elmira or Jamestown.

If the EAR seeks to project the impact of expenditures on the regions in the state likely to be affected by HVHF gas development, it needs to disaggregate these impacts to show what proportion of the impacts in the three largest sectors (real estate and rental; professional, scientific, and technical services; and management of companies) is actually likely to occur in the representative regions. Although the authors assert that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. This assumption contravenes economic knowledge about agglomeration economies and company location behavior, which indicates that specialized services will remain in higher order centers (like New York City) and not re-locate to counties, especially rural counties, where drilling is occurring. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs (Headwaters Economics, 2011).

B. The Distribution of Economic Impacts in New York Versus Those in Other States

Nationally, Texas and Oklahoma are the major beneficiaries of natural gas development, wherever production takes place in the United States. According to *Mine K. Yücel and Jackson Thies of* the Dallas Federal Reserve (2011): “An increase in oil and gas production **anywhere** benefits the state (of Texas) and its energy sector, which provides oilfield machinery and energy services to the rest of the world.” See also subsection C, below. Nevertheless, because of its capital intensity, natural gas drilling does not have a large employment impact, even in Texas. Gas development thus plays a minor role in the economies of even these resource extraction states.

C. The Distribution of Highly-Skilled Jobs

Petroleum engineers are listed as one of the most common occupations in the oil and gas industry (EAR, 3-8, Table 3-10). The geographical analysis of this occupation by occupational employment statistics indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. In 2010, the total U.S. employment of petroleum engineers was 28,210, of which 15,510 were employed in Texas, and 10,380 of those worked in the Houston metropolitan area. Thus, even in Texas, the employment in this occupation is concentrated in the Houston metropolitan area, not in the drilling areas.

The likely distribution of highly paid occupations is demonstrated by the Bureau of Labor Statistics (BLS) Occupational Employment Statistics Data on one of the most numerically significant skilled occupations, that of petroleum engineer. According to the BLS, only a fraction of petroleum engineers (in the hundreds) are employed in non-metropolitan areas in the U.S. (BLS, 2010). This data, too, suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs related to the oil and gas industry.

III. Inadequacy of Proposed Mitigation Measures

A. Mitigation Measures That Address Potential Impacts Related to Volatility in the Pace and Scale of Drilling Should Be Required

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator's identification of inconsistencies with comprehensive land use plans. The measures identified are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions (Headwaters Economics, 2011). This assessment is also completed for National Environmental Policy Act compliance when development proceeds on public lands.

Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur, enables local government to anticipate and develop strategies to mitigate cumulative impacts (Sammons, Dutton and Blankenship, 2010). The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal, pipeline construction) in the area to be affected.
A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

Another mechanism for reducing the unpredictability and uncertainty of natural gas production at the regional scale is being developed by the Nature Conservancy with pilot projects in the Western States and planned in Pennsylvania (see Kiesecker et al, 2010). Their objective is a science-based, landscape-scale approach to Marcellus gas development that will secure measurable conservation outcomes, while enhancing industry's ability to operate in an environmentally sensitive and cost-efficient manner. To be enforceable, this cooperative approach, based on a partnership between the operating company and local public officials, needs to be codified in a binding agreement. Partnerships of this sort may be useful, but they cannot serve as mitigation for significant adverse socioeconomic impacts unless they are mandatory.

B. Mitigation Should Address Housing and Urban Development Impacts, Including Sprawl and Excess Substandard Housing

Evidence from Pennsylvania and Western shale plays indicates the likelihood of negative impacts on the quality of the temporary and permanent housing stock, a high rate of homelessness for extensive periods, and displacement of low income people from affordable housing. Given the presence of small cities in the region, mitigation measures should include required assistance to cities in the affected region to encourage new housing development in already-developed urban areas and the development of temporary housing that could be transformed to other uses once the influx of transient workers resides. Mitigation measures should also address the impacts of the loss of affordable housing units in the region.

C. Mitigation Should Address Long-Term Social and Economic Impacts

The RDSGEIS and the EAR describe significant adverse social and economic impacts, such as those produced by the volatility of natural gas development on the housing market of regions where development occurs. No mitigation strategies are recommended to alleviate long-term costs that are reasonably assumed to be associated with natural resource development, including HVHF development. Mitigation strategies directed at these long-term costs to the affected regions need to be developed and described in the SGEIS. Mitigation strategies also need to be developed to address the resource depletion phase of the exploration, drilling, development and resource depletion process. In this phase, population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

D. Mitigation Should Require That Monitoring Reports Projecting Industry Development Plans Be Prepared by the State in Cooperation with Industry and Filed Semiannually

As development activities begin and progress, the information provided in initial projections should be required to be confirmed or revised on a semiannual basis. Information provided in the semiannual assessment and projection should include: (1) employment for each activity; (2) identification and location of contractors; (3) demographic characteristics and residence of employees who will be working in the region. This information is critical to forecasting and meeting housing and service demands.

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Attachment 6

Meliora Design, LLC.

Technical Memorandum

Review and Analysis of the

Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

and the

Draft New York State Department of Environmental Conservation SPDES General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing

January 10, 2012

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Introduction

This memorandum reviews both the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) *on the Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs* and the Draft *New York State Department of Environmental Conservation SPDES General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing* (SPDES HVHF GP). The focus of this memorandum is the potential impacts on surface water resources that result from land disturbance and alteration, including impacts related to increased erosion and sedimentation, as well as impacts that result from increased and altered stormwater discharges. The review of both the RDSGEIS and the Draft SPDES HVHF GP are co-dependent, as the Department has indicated that general or (substantially similar) individual SPDES permit coverage will be the primary means of regulatory oversight for HVHF operations (and presumably for other low-volume hydraulic fracturing activities, although this is not explicitly stated).

The land disturbance associated with HVHF construction activity has the potential to negatively impact surface water quality in the same manner as other land disturbance activities, as discussed in Attachment A, and the lack of a local government land development review process increases the potential for greater water quality impacts through the increased disturbance of steep slopes, sensitive areas, proximity to unmapped headwater streams, etc. Furthermore, the land disturbance nature of HVHF operations results in a dispersed industry across a wide area, with a large (and unknown) number of stream crossings and an increase in road traffic and gravel road construction. The documented water quality impacts of roads (including gravel roads) are also discussed in Attachment A.

Summary of Key Findings:

The RDSGEIS provides only a very brief generic discussion on the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). While the RDSGEIS acknowledges that this land disturbance has potential for water quality impacts, and the Department has made a positive determination that a SPDES permit is required, the RDSGEIS provides little specific discussion or consideration of the land disturbance and surface water quality impacts. Specifically:

- The RDSGEIS makes no attempt to evaluate the cumulative impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the 1992 GEIS, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts with little industry-specific consideration, and no consideration of total or cumulative impacts. **A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential for a full environmental impact analysis, and to inform any determinations by the Department on the appropriate regulatory permitting requirements.**
- The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream

crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft SPDES HVHF GP. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current Department regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. **The RDSGEIS should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed Department requirements to regulate and mitigate these impacts.**

- The RDSGEIS does not adequately address private well setbacks, road spreading of brine, gather lines, fueling areas, on-site disposal of drill cuttings, and acid rock drainage. Each of these has the potential to significantly impact and impair water quality. **The RDSGEIS should provide additional information regarding each of these impacts, specifically with regard to landowner notification of well setbacks, cumulative impacts of road spreading of brine, minimizing stream crossings with gather lines, addressing the non-stationary status of fueling areas, and consideration of ARD impacts from disposal of drill cuttings.**
- With the exception of watersheds that serve as unfiltered drinking water supplies and receive Filtration Avoidance Determination (FAD) status, the RDSGEIS and SPDES HVHF GP do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support that proposed setbacks are adequate to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep

slopes). **The RDSGEIS should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.**

- Even if the proposed setbacks discussed in Chapter 7 were adequate, they are not clearly coordinated with the EAF requirements in Appendices 4, 5, 6 and 10 and the Draft SPDES HVHF GP mapping and documentation requirements (and the SPDES HVHF GP is presumably the regulatory mechanism for compliance). **The Draft SPDES HVHF GP mapping requirements must be at a scale and level of site-specific detail to accurately reflect the required information, and SPDES mapping requirements must be consistent with those identified in the RDSGEIS.**
- The RDSGEIS fails to provide a clear and accessible process for public and local government access to site specific HVHF activity information. At the same time, DEC expects local governments to provide notice to the Department if a proposed HVHF activity is not in compliance with local zoning or land use regulations. This approach puts the regulatory burden on a local government that wishes to challenge a proposed permit application while simultaneously failing to provide local government with access to the necessary information. **The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public,** with supporting public access to all information regarding proposed land disturbance activity, and reasonable timeframes and processes for comments and addressing of concerns.
- The Draft SPDES HVHF GP is essentially a compilation of the Department's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. Based on the very limited discussion of land disturbance and surface water impacts in the RDSGEIS, it is uncertain whether a general permit process will be

sufficient to protect water quality. It is also not clear that an industry that is NOT subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF operations.

- The general permit process does not provide a timeframe (and process) for public review, comment, and objection to any or all parts of a general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the Department and meeting minimum performance requirements. There is no opportunity for public access to information or appeal of permit coverage. **It is essential that the SPDES HVHF GP provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site *before* general permit coverage is granted. It is essential that the permit coverage timeline be adjusted to provide for public comment and appeal.**

Comments on the RDSGEIS

As previously indicated, the discussion in the RDSGEIS on the total land use impacts and associated water quality impacts as a result of both land disturbance during construction and post-construction stormwater management is extremely limited.

Comment 1:

Chapter 5, Natural Gas Development & High-Volume Hydraulic Fracturing. Section 5.1 of the RDSGEIS discusses the impacts of Land Disturbance, including Access Roads, Well Pads, Utility Corridors, and Well Pad Density. See pages 5-6 through 5-31. Estimates of land disturbance associated with each of these well drilling activities are provided but total or cumulative land disturbance is not addressed.

Comment 2:

Section 5.1 *Land Disturbance* identifies a number of types of land disturbance activities associated with HVHF including utility corridors (including gathering lines), compressor facilities, and access roads associated with compressor facilities. The Draft HVHF SPDES permit (Part III.A.3) does NOT address construction of gathering lines, compressor facilities, or the access roads associated with compressor facilities.

Recommendation: The RDSGEIS must provide a process for regulation and mitigation of the land disturbance impacts associated with gathering lines, compressor facilities, and the access roads associated with compressor facilities. The RDSGEIS cannot identify the SWPPP as "*the principal control mechanism to mitigate potential significant adverse impacts from stormwater runoff*" (Section 7.1.2 SGEIS) without providing for adequate management requirements for all HVHF activities in the Draft SPDES HVHF GP.

Further discussion in Section 5.1 provides some analysis of disturbance areas associated with gathering lines, compressor stations, and access roads to

compressor stations, but specific consideration of the impacts of these activities is not discussed in Chapter 6, and specific recommendations to reduce the impacts of these components (such as co-locating gathering lines along well pad access roads) is not provided in Section 7 or the Draft HVHF SPDES permit.

Comment 3:

Section 5.1.1 *Access Roads* indicates that roads may be placed across ditches, but does not discuss the construction or widening of access roads that cross streams or wetlands. The potential impacts of such crossings are not discussed in Section 6.1.2, *Stormwater Runoff* or other portions of Section 6, nor are the mitigation measures for road crossings of streams and wetlands addressed in Section 7.1.2 *Stormwater.* Setbacks for roads from streams and wetlands are not specifically addressed in either Chapter 7 or the Draft HVHF SPDES permit, nor are requirements for stream and wetland crossings provided. It is not clear as to whether an Article 15 Stream Disturbance Permit from the DEC will be required for HVHF projects and what compliance might entail. It is noted that Photos 5.1 and 5.2 of the RDSGEIS portray access road stream crossings, but the impacts of the stream crossing are not addressed.

Road crossings of streams and wetlands will be unavoidable during the development of HVHF sites. Section 5.1.1 acknowledges that the length of road may be influenced by selecting a route to avoid environmentally sensitive areas, but mitigation measures recommending such route selection are not specifically addressed in either Chapter 7 or the Draft HVHF SPDES Permit. Estimates of the number and extent of anticipated stream and wetland crossings are not provided in Section 5.1.1.

Recommendation: The proximity of roads to streams and wetlands, and the unavoidable need to cross streams and wetlands, increases the risk that erosion and sedimentation will cause measurable impacts on water quality. Poorly constructed stream crossings can directly impact aquatic communities.[3, 7] Excessive sediment

levels are one of the primary threats to US surface waters[10] and have multiple effects on stream health. The RDSGEIS should provide estimates of the anticipated extent of road crossings of streams and wetlands, as well as an evaluation of the potential environmental impacts of these crossings. Furthermore, avoidance and mitigation measures should be addressed in the RDSGEIS and incorporated into the regulatory process. Specific requirements and guidelines to mitigate the impacts of stream and wetland crossings should be provided.

Recommendation: If the SPDES HVHF GP is to be the primary mechanism for regulation, then the permit should include a defined documentation process to require the applicant to reduce the number and extent of stream crossings. This section should be incorporated into Part IV, *Contents of the Construction SWPPP*, as a requirement of Section A.1 and include both mapping requirements and narrative that documents the need for each stream crossing and explanation as to why any individual stream crossings cannot be reduced or combined. Road crossings on areas specifically in conflict with local government land use regulations should be identified, as well as road crossings on steep slopes erodible soils, or intact woodlands.

Comment 4:

Section 5.1.2 *Well Pads* notes that well pad size is determined by site topography, but no estimates are provided regarding the impact of slope on well pad size and disturbance footprint, and the increased impacts on erosion and sediment discharge. The area of disturbance can be increased by up to 50% on slopes exceeding 15 degrees[8] (the Draft HVHF SPDES permit allows disturbance on slopes up to 25% in AA or AA-s watersheds. It is not clear that there is a limit on slope construction in other watersheds). The stormwater and erosive impacts of well pads on steep slopes continues through the life of the well pad. At a minimum, the Draft SPDES HVHF GP should preclude well pad construction on slopes over 25%.

Recommendation: Section 5.1.2 should provide some evaluation of the anticipated increase in well pad disturbance as a function of slope (and required cut and fill) as a result of the impacted terrain conditions specific to New York. Section 7 of the RDSGEIS should provide discussion of specific mitigation measures to reduce the impacts of well pad construction on slopes. The HVHF SPDES permit should include specific requirements to reduce construction of well pads on steep slopes, limits on steep slope construction in all watersheds, and provide discussion and requirement of implementation measures to reduce the long-term water quality impact of well pads on slopes when such systems are constructed. Additional measures to prevent sediment discharge from construction on steep slopes should be defined and required as part of the facility SWPPP. It is not clear that the general requirements of either the 2005 New York State Standards and Specifications for Erosion Control or the 2010 New York State Stormwater Management Design Manual provide sufficient specific guidance to address the additional impacts associated with well pad construction on slopes. Both erosion control measures and stormwater measures must be adjusted in their design to account for the greater water quality impacts of well pad location on slopes.

Comment 5:

Section 5.1.2 *Well Pads* and **Section 5.1.4** *Well Pad Density* do not provide any specific information or estimates of well pad or HVHF facility location or density with regards to watershed drainage areas, or analysis of the anticipated density of well pads within intermittent or perennial headwater stream drainage areas. Section 6 does not discuss the impacts on water quality of well pad density within the drainage area of an intermittent or perennial stream. Headwater and intermittent perennial streams originate with a drainage area of 5.5- to 37-acres[5], increasing the likelihood of a HVHF well pad being within several hundred feet of an intermittent or perennial stream, and the likelihood that the disturbance will represent a sizable portion of the total drainage area to a headwater stream (i.e. 7.4 acres of total disturbance for a multi-well pad during the drilling phase, and 1.5

acres of disturbance during the drilling phase could represent a very large percentage of the drainage area of a headwater or small stream).

Recommendation: Current research[2] indicates a positive relationship between stream water turbidity and well density within a drainage area or watershed. The RDSGEIS does not provide any analysis or consideration of potential levels of watershed disturbance as a result of HVHF activities, and the resulting potential impacts on water quality, although such an analysis is well within current mapping and GIS capabilities and should be included in the RDSGEIS.

Comment 6:

While some mention of gathering lines is included in **Section 5.1.3** *Utility Corridors*, including an estimate of 1.66 acres per well pad, no discussion is made of the anticipated extent of stream crossings, or the cumulative levels of land disturbance associated with gathering lines on a watershed or other basis. No further discussion is provided in Chapters 6 and 7 specific to gathering lines. It is unclear exactly how the current DEC permit process for pipeline stream crossing is adequate to protect water quality from either a land disturbance or stream crossing impact from gathering lines, or how gathering line construction will be addressed and/or coordinated with the Draft HVHF SPDES permit process (which does not currently address gathering lines).

Recommendation: This issue requires additional consideration in the RDSGEIS, and the specific permitting requirements for gathering line stream crossings should either be identified in the Draft HVHF SPDES permit or coordinated with this permit so that impacts are reduced. Specifically, measures to reduce the impact of gathering line stream crossings (and general construction) by coordination of this construction with other well site needs should be required.

Comment 7:

Chapter 6, Potential Environmental Impacts. Section 6.1.2 *Stormwater Runoff*, discusses both stormwater impacts and erosion and sedimentation construction issues. However, this discussion is very general in nature, comprising only 1-1/4 pages within Chapter 6 for both of these topics. No discussion is provided regarding the specific magnitude and issues of concern associated with stormwater and erosion impacts from the various HVHF activities (i.e. well pad construction, and variations on well pad construction such as disturbance footprint from construction on steep slopes). Rather, it is simply noted that the potential for water resource impacts exists, and that these impacts may cause increased runoff volumes, greater erosive forces, heightened sediment loads, etc.

Recommendation: Research data and engineering methodologies are available to quantify the potential adverse water quality impacts, either on a "typical" facility basis or an anticipated watershed basis (using the estimates of acreage developed in Section 5). Such analysis would provide at least some basis for determining whether the requirements of the Draft HVHF SPDES GP are adequate for the industry. These estimates would also provide information on the cumulative impacts of HVHF on water quality and stream health and should be included in the RDSGEIS.

Comment 8:

Chapter 7, Mitigation Measures. Section 7.1.2 *Stormwater,* discusses stormwater management in general terms, with a non-specific discussion of the particular issues associated with HVHF stormwater and erosion. Much of the generic discussion focuses on pollution prevention from exposed industrial activities. Less than one page addresses stormwater management mitigation measures related to land use changes, and one-half page addresses mitigation associated with stormwater and erosion issues from construction activities. Section 7.1.3 discusses spills and

containment, which is also addressed in the SPDES HVHF GP. However, much of this discussion is focused on industrial spill control, not stormwater impacts.

Chapter 7 indicates that the Department intends to issue a single SPDES General Permit that will encompass all issues of construction stormwater and erosion control, post-construction stormwater management, industrial stormwater management, and pollution prevention/spill control. Specifically, page 7-26 states: *The Department has determined that natural gas well development using high-volume hydraulic fracturing would require a SPDES permit to address stormwater runoff, erosion, and sedimentation. The SPDES permit will address the construction of well pads and access roads and any associated soil disturbance, as well as provisions to address surface activities associated with high-volume hydraulic fracturing for natural gas development. Additionally, during production of the natural gas, the Department will require coverage under the SPDES permit to remain in effect and/or compliance with regulations. The Department proposes to require SPDES permit conditions, a Comprehensive SWPPP (stormwater pollution prevention plan), and both structural and non-structural Best Management Practices (BMPs) to minimize or eliminate pollutants in stormwater. The Department is proposing the use of a SPDES general permit for high-volume hydraulic fracturing (HVHF GP), but the Department proposes to use the same requirements in other SPDES permits should the HVHF GP not be issued.*

Recommendation: The HVHF SPDES permit should be specific to this industry and impose requirements that reflect the lack of local government review and approval of the land development activities associated with the industry. The RDSGEIS should specifically identify the areas where additional permit requirements specific to the industry are necessary to protect water resources.

Comment 9:

Section 5.1.1 *Access Roads* notes that roads may be constructed by placing crushed stone or gravel, but Section 6 does not specifically address the water quality issues

associated with the long-term use of gravel roads (after construction), nor does Section 6 provide any estimate of potential pollutant loadings associated with gravel roads, specifically estimates of sediment generation. Research data[4] indicates that gravel roads can be a significant source of sediment pollution, and data to support sediment pollutant load estimates is available but requires an estimate of the anticipated extent and area of gravel access roads to be constructed, which is not provided in Section 5.1.1. Gravel access roads serving HVHF will be subject to undefined levels of truck traffic, which has a greater impact on road condition and erosion than regular vehicle traffic. Section 6.1.2 *Stormwater Runoff* discusses the impacts of sediment on streams and notes that "*steep access roads…pose particular challenges.*" **Section 7.1.2** *Stormwater* indicates that the construction of access roads will be addressed by the SPDES permit, but neither Section 7.1.2 nor the Draft HVHF SPDES permit provide specific recommendations to reduce the length and width of gravel access roads, to reduce construction access roads on steep slopes, or to reduce the specific impacts of gravel road and sediment generation once the construction period has ended. General reference to the State stormwater manual is not sufficient for this issue as it relates to HVHF. There is no requirement in the Draft HVHF SPDES mapping requirements to indicate or accurately depict the length, width, or slope of gravel access roads. Since these areas will generate sediment pollutants through the life of the project, specific guidelines to mitigate pollution from access roads are warranted.

Recommendation: The RDSGIES should provide more detailed information on the specific impacts of gravel access roads with regards to sediment generation, and the estimated extent of potential pollutant loads. Section 7 of the RDSGEIS should provide discussion of specific mitigation measures to reduce the impacts of access road construction. The HVHF SPDES permit should indicate specific requirements for the documentation of access road lengths and widths, and requirements to reduce construction on steep slopes, reduce road width, and implement other measures to reduce the water quality impact of access roads. Measures to maintain

gravel access roads in a manner that prevents sediment discharge (over the life of the project) should be defined and required as part of the facility SWPPP.

Comment 10:

Section 7.1.11.1 *Setback from private well*, Section 7.1.11.1 states that "The Department proposes that it will not issue permits for high-volume hydraulic fracturing within 500 feet of a private water well or domestic supply spring unless waived by the landowner." However, the Draft SPDES permit does not require the applicant to map the location of private water wells or springs that may be within 500 feet, or to notify the landowner. Coverage under the GP is granted within 30 calendar days of the Department receiving the NOI (and meeting the requirements of Part II.B.2). How will the Department or the applicant be aware of the existence of private water wells within 500 feet? This is also not included in Section 5 of the Environmental Assessment Form, but IS included in the Proposed EAF Addendum Requirements for HVHF. It is not clear how 500 feet was determined as sufficient distance to support a private well from HVHF activities as no supportive reasoning is provided.

Recommendation: Require that all private water wells and domestic supply springs within 2,640 feet and 500 feet, respectively, to be located on the Site Map (prepared under Part IV.C.1.b and as a requirement to the Site Map in the SWPPP). The NOI form should require that the applicant confirm that there are no such wells within 500 feet, and provide proof to the Department of landowner waiver receipt (by certified mail or similar means).

Recommendation: The SWPPP should identify the private water well or spring in the narrative (Part XI.3) and identify measures undertaken to protect the private well and to address emergency spill situations.

Comment 11:

Section 7.1.11.2 *Setbacks from Other Surface Water Resources* states "Existing regulations prohibit the surface location of an oil or gas well within 50 feet of any 'public stream, river or other body of water.'" The 1992 GEIS proposed that this distance be increased to 150 feet and apply to the entire well site instead of just the well itself". The Draft HVHF SPDES permit (Section I.D.4) requires a setback of 150 feet from the well pad and perennial or intermittent streams, but does not address setbacks from other HVHF site components.

Recommendation: As discussed later in specific recommendations associated with the Draft HVHF SPDES permit, required setbacks of any length are meaningless unless the water features are accurately identified and located. A USGS 7-1/2 minute topographic map, at a scale of 1" = 2000' is inadequate for this purpose. It is essential that the Draft HVHF SPDES permit require mapping at a scale that can accurately depict both existing natural features (such as steep slopes and headwater streams) as well as proposed HVHF components.

Comment 12:

There are benefits associated with a single SPDES GP (or a single individual SPDES permit) that addresses construction, post-construction stormwater, and industrial stormwater and spill containment for each project in one permit. These benefits include a comprehensive evaluation of each project, potential continuity in responsible facility personnel, and consistency of management practices through both construction and operation.

However, the Department is largely drawing on the current requirements in the existing SPDES general permit for construction (New York State Department of Environmental Conservation SPDES General Permit For Stormwater Discharges From Construction Activity Permit No. GP-0-10-001) and the existing SPDES general permit for industry (New York State Department of Environmental Conservation SPDES Multi-Sector General Permit For Stormwater Discharges Associated With

Industrial Activity Permit No. GP-0-06-002). The Department is combining many (but not all) requirements of these two GPs into one HVHF GP and, in doing so, does not include provisions that would otherwise be required of permittees seeking either of the existing permits alone..

For the issues of site disturbance, stormwater management, setbacks, disturbance of sensitive features, erosion, and other impacts associated with many non-HVHF land development projects and industrial activities, there is an additional level of professional review and regulation in the form of local laws, regulations, plans or policies implemented by the local planning board or authorized board. In other words, for non-HVHF projects, such as land development projects, there is often a local project review of proposed plans by a professional reviewer knowledgeable in local conditions, supported by the review of an authorized board whose members possess local knowledge. Local regulations are likely to impose more rigorous mapping requirements, stormwater calculations, and design detail than those imposed in a Department general permit, and furthermore, project submissions receive local, professional review. In these circumstances, successful design and compliance (with the requirements of Department general permit) is more likely when supported by a secondary level of performance requirements and review at the local level.

The issuance of a single GP for HVHF (that encompasses many requirements of both existing Department GPs) will not have the benefit of local review and specific local performance requirements. The potential impacts of HVHF projects on land disturbance, stormwater, erosion, sensitive sites, etc. is at least as significant (if not more significant) than other, locally regulated land disturbance and industrial activities. HVHF is also a "heavy" industry that will be located in many areas unaccustomed to heavy industry.

Recommendation: The Department should provide the opportunity for local review by revising the SPDES HVHF GP to address compliance with applicable local ordinances. For instance, those activities which would typically require issuance of

GP-0-10-001 should be required to comply with all local ordinance requirements as they apply to HVHF activities. Additionally, the Department should require SPDES HVHF GP permittees to provide written notification to the Department from the affected local governments that the conditions of local ordinances are met to the satisfaction of the local governing authority prior to issuance of the permit. Comment 14 below discusses this further.

Comment 13:

HVHF compliance with the requirements of the GP are largely self-reviewing and self-monitoring, as facilities are required to develop and implement a SWPPP, but there is generally no review of the SWPPP unless the Department elects to request and review the SWPPP for a specific facility. Absent this specific request by DEC, the SWPPP is simply maintained on-site. In addition, DEC does not propose any mechanism that would enable it to effectively evaluate successful implantation of a SWPPP.

Recommendation: The SPDES HVHF GP should be revised to make public all documents, specifically including the SWPPP, available for review by the Department and the public. In all instances, the Department should establish a mechanism to routinely review whether applicants have successfully implemented their SWPPPs. Dated digital photos that support inspection and compliance per permit and SWPP requirements should be a requirement for permit coverage.

Comment 14:

Chapter 8 , Permit Process and Regulatory Coordination; **Section 8.1.1.5** *Local Planning Documents* of the SGEIS states:

> *However, in order to consider potential significant adverse impacts on land use and zoning as required by SEQRA, the EAF Addendum would require the applicant to identify whether the proposed location of the well pad, or any*

other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies. The applicant would also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s). For actions where the applicant indicates to the Department that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans or policies, or is not covered by such local land use laws, regulations, plans or policies, the Department would proceed to permit issuance unless it receives notice of an asserted conflict by the potentially impacted local government.

This approach is problematic. While it is the responsibility of the applicant to determine whether or not there are any conflicts, it is up to the potentially impacted local government to provide notice to the Department of an asserted conflict that has not been identified by the applicant. Although the RDSGEIS states that the Department would notify local governments of all applications for high-volume hydraulic fracturing in the locality, through the use of an electronic notification system to local government officials (see DSGEIS at 8-4), DEC offers no guarantee that this system will be in place prior to the issuance of permits and does not specifically describe when in the permitting process such notification to local governments will occur. These are critical issues that should be addressed. Further, it is unclear how the Department will determine *"whether significant adverse environmental impacts would result from the proposed project that have not been addressed in the SGEIS and whether additional mitigation or other action should be taken in light of such significant adverse impacts." RDSGEIS at 8-5.* It is also not clear as to whether this determination process applies to all HVHF GP applicants, or only those subject to SEQRA determination.

Recommendation: In consideration of the Department's decision to regulate HVHF under a single SPDES general permit without the important supplemental benefit of local review and local laws, regulations, plans or policies (that virtually all other

land development and industrial construction projects are subject to when obtaining SPDES permit coverage), obtaining General or Individual Permit coverage (for all HVHF projects) should also require the applicant to notify the local government (as well as the Department) that there are no conflicts with local laws, regulations, plans or policies, and to provide supporting documentation of the evaluation to the local government and Department. This will allow local governments to receive the necessary information to "assert" a potential conflict that may not have been identified by the applicant. Without this critical information, local governments cannot be expected to "assert" a potential conflict to the Department.

Comment 15:

As discussed above, Section 5.1 of the RDSGEIS provides estimates of land disturbance for well pads and associated construction activities (roads, utility corridors, compressors, etc.), including total estimated disturbance per pad for multi- and single-well pads. The RDSGEIS notes that most wells will be multi-pad wells with a net disturbance of 7.4 acres per pad (reducing to 1.5 acres per pad during production). A spacing of 640 acres per multi-well pad is presented in Table 5.1 of the RDSGEIS. However, no consideration is provided of the anticipated disturbance and well pad density on a watershed basis, or proximity to streams and anticipated stream crossings, and no consideration is provided on the potential individual and cumulative effects on stream health.

A recently published study of natural gas development in the Fayetteville and Marcellus formations in Arkansas and Pennsylvania[2] used current topographic data, well development data, and readily available land use analysis computer modeling tools (ArcHydro Version 1.3) to evaluate both the overall well pad density per drainage area and well proximity to streams in these formations in Arkansas and Pennsylvania. This desktop analysis was further supported by in-stream turbidity measurements in seven different drainage areas with different well densities.

This report had several significant findings, most notably it "identified a positive relationship between stream water turbidity and well density. Turbidity was not positively correlated to other land use cover variables." (Entrekin, et al, "Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters, pg 507). The report further concluded that "preliminary data suggest that the cumulative effects from gas well and associated infrastructure development are detectable at the landscape scale."

This study also determined that approximately 17% of the active Pennsylvania wells were within 100 meters (328 feet) of a stream, and all wells were within 300 meters (984 feet) of a stream. Gas wells "were located, on average, 15 km (9.3 miles) from public surface-water drinking supplies and 37 km (23 miles) from public well water supplies." The report noted that "although wells are generally constructed far from public drinking-water sources, there is potential for wastewater to travel long distances given that many of the components, such as brines, will not settle out or be assimilated into biomass." In other words, due to the nature of material from HVHF wells, discharges that reach streams (due to inadequate stream setbacks) may travel to public drinking supplies, even if the surface water supplies are distant to the well.

Chapter 6 of the RDSGEIS broadly identifies potential environmental impacts on water resources (Section 6.1), including polluted stormwater runoff and spills. The RDSGEIS does not specifically discuss the cumulative impacts of land disturbance on surface water quality (i.e. whether turbidity or other measures of stream impact increase with well density). The RDSGEIS makes no attempt to estimate well density and land disturbance on a drainage area basis with regards to water quality impacts or consideration of specific watersheds and designated uses. No specific consideration is given to the topography and stream density of New York State with regards to land disturbance and proximity to surface waters.

Such an analysis would provide a far better estimate of potential surface water impacts and the extent of anticipated land disturbance on a watershed or drainage area basis. This information would inform the state as to the watershed impacts

from HVHF activities, and provide some additional basis for well density in different watersheds. It would also better inform the decisions regarding setback distances discussed in Sections 7.1.5 and 7.1.11.2.

As discussed previously, most headwater and small perennial streams are not indicated on USGS 7-1/2 minute topographic quadrangles, and hence will not necessarily be identified under the current mapping requirements in the Draft HVHF SPDES permit. Headwater streams generally originate with a surface drainage area of 5 to 37 acres.[5] The study discussed above had a stream threshold of 12.4 acres. With a disturbance footprint of 7.4 acres per multi-well pad, drilling activities could potentially impact as much as 60% of the land area in a headwater stream drainage area (assuming 12.4 acres per drainage area). The extent and impact of land disturbance in headwater streams is not addressed in any manner in the RDSGEIS.

Recommendation: The RDSGEIS should provide some technically supported evaluation of the anticipated well density on a drainage area basis, with consideration of water quality impacts. The analytical land use tools, data, and models available today are significantly more robust than the environmental tools available during the development of the 1992 GEIS (and such tools are often used to support TMDL determinations). In other words, the density of anticipated land disturbance and proximity to streams and wetlands could easily be mapped and evaluated using anticipated development rates and relevant information from states such as Pennsylvania. At a minimum, representative watersheds could be evaluated in detail to represent anticipated conditions, and using topographic data and average proximity to streams could be estimated. Relevant well drilling data is also available from other states such as Pennsylvania. High-volume hydraulic fracturing is "distinct from other types of well completion" as noted in the RDSGEIS, and warrants additional consideration.

This type of land use and density evaluation will allow the Department to better assess the potential impacts of high-volume hydraulic fracturing on both watershed

land use and proximity to streams, and can provide a technical basis for HVHF well density and setback decisions. It can also inform decisions regarding well density and setbacks in waters with TMDLs. But at this time there is no watershed impact consideration of HVHF well location and density. It is unclear whether the various setbacks discussed in the RDSGEIS are adequate to protect water resources during HVHF activity, or whether these setbacks merely represent an arbitrarily selected value.

Recommendation: To facilitate Department identification of wells that may have an impact on small headwater streams, the Draft SPDES HVHF GP could require that each well pad application document the total amount of anticipated land disturbance, and the percent of land disturbance within the drainage area of the well pad location. This is not a difficult estimate for the permit applicant to develop using current mapping tools, and will provide some indication that adjacent streams may be small and especially vulnerable to land use impacts.

Comment 16:

Section 7.1.3.1 indicates that fueling tanks are considered "non-stationary" at well pads, and therefore exempt from Department storage and registration requirements. Section 7.1.3.1 does state that secondary containment is required for all fueling tanks, and that fueling tanks would not be positioned within 500 feet of perennial or intermittent stream, storm drain, wetland, lake or pond.

It is unclear how this requirement will be met or maintained, especially in light of the fueling tanks being "non-stationary." Specific requirements are not reflected in the Draft HVHF SPDES permit, either in the general SWPPP requirements or the Fueling Area requirements. It is unclear how this setback will be identified and maintained, and how the Department intends to ensure compliance. The requirements for fueling areas in the Draft HVHF SPDES permit are the same general requirements applied to all industrial facilities and do not have any specific consideration of the nature and conditions of HVHF sites and fueling needs.

Recommendation: The RDSGEIS and Draft HVHF SPDES permit must address the issue of containment for "non-stationary" fueling tanks, and all other non-stationary tanks.

Comment 17:

The RDSGEIS **Section 7.1.7.2 Road Spreading** indicates that NORM concentration data in brines is insufficient to allow road spreading under a BUD, and that as more data becomes available the Department will evaluate the BUD petitions. However, the RDSGEIS is inadequate in that no consideration has been made of the total potential increase in chlorides on roads as a result of the HVHF industry disposing of brines in this manner, and the anticipated levels of chlorides and other compounds in the brine. Again, the RDSGEIS has not considered the cumulative impacts of the generation of this material and the potential volume of material application on roadways. No estimate is made of the volume of production brine that may be disposed of on roadways. No consideration is provided regarding what might be "safe" levels of chlorides (or other compounds) in different situations, or what other additional compounds that may be found in production brine that would preclude the use of the material for roadway application. The requirements in the current BUD have no basis as being sufficient for protecting water quality, and are generally self-monitored by the industry.

Unless the use of production brine is demonstrated as being a beneficial use for the public in roadway safety, application to roadways should not be seen as a viable disposal method. Much more research on the effects of the material on plant and aquatic systems is required.

Recommendation: The RDSGEIS should provide better information regarding anticipated brine production levels and disposal needs as a result of HVHF activity. Future authorization of the application of brines under a BUD should not be allowed until this information has been developed and provided for public review and comment.

Comment 18:

Section 7.1.9 Solids Disposal indicates that the generation of acid rock drainage (ARD) may occur as the result of material from certain portions of the Marcellus shale. The RDSGEIS indicates that an ARD mitigation plan would be required for in-site burial, but is not required for off-site disposal.

No estimate is provided within the RDSGEIS of the potential amount or magnitude of the generation of this material, and whether or not the amount of ARD material is of concern, or within which watersheds such material may be anticipated. The generation of ARD is of significant concern and impact on watershed health, and warrants more detailed analysis of the anticipated locations and extent where ARD may be an issue. It is not clear if this is expected to be an extensive concern, and no consideration is made of the amount and extent of the ARD material encountered in other states such as Pennsylvania, and how much this material has created additional acid discharge problems in other states. This issue is not addressed in the HVHF SPDES draft permit.

Recommendation: Estimates of the anticipated extent of such material should be included in Chapter 6.1.9.2, and coordinated requirements for ARD treatment (as discussed in Section 7) incorporated into the Draft HVHF SPDES permit. This material has significant potential impact to water quality.

Comment 19:

The EAF addendum should clearly define the process and timeline for notification of local government, and for the Department's process for determination of permit applicability when notice is received from the applicant or local governments that a conflict with local laws, regulations, plans or policies exists. Furthermore, the EAF addendum should address the issue of HVHF GP coverage upon NOI submission when such local conflicts exist.

Recommendation: Coverage should NOT begin until proof of notification to local governments has been received by the Department, local governments have been provided sufficient information and time to "assert" any unidentified potential conflicts, and the Department has made project specific determinations regarding the impact of identified or asserted conflicts. A timeline and process must be defined.

Comment 20:

EAF Appendix 12 Beneficial Use Determination (BUD) Notification Regarding Road Spreading states that "Any person, including any government entity, applying for a Part 364 permit or permit modification to use production brine from oil or gas wells or brine from LPG well storage operations for road spreading purposes (i.e. road deicing, dust suppression, or road stabilization) must submit a petition for a beneficial use determination (BUD)." This petition must include sampling data (although the sampling parameters are limited), a map indicating roads where brine is to be spread, and a general narrative of practices to be implemented, including avoiding applying brines within 50 feet of a stream or waterbody, avoiding application during rainfall periods or on slopes greater than 10 percent.

Chlorides are toxic to many plants and freshwater aquatic plants and invertebrates[14] with levels as low as 30 mg/L toxic to plants, and at 1000 mg/L toxic to aquatic plants and invertebrates. Chlorides also impact the use of surface water for potable water sources.

While chlorides are applied to roads during snow and ice conditions for safety reasons, many state Departments of Transportation have begun programs to significantly reduce the use of chlorides and implement alternative de-icing practices to reduce the impacts of chloride on both vegetation and stream system health.

Recommendation: Additional analysis of potential impacts must be done to evaluate potential impacts from road spreading, including analysis to support that the proposed setback criteria are sufficient to protect water quality, as well as to define required sampling requirements for BUD petitions.

Comment 21:

In addition to defining the processes and timelines for review and notification requirements, coordinating permit approvals and public participation activities would ensure compliance with all applicable statutes and eliminate any conflicts that may arise. Regulatory permit tracking, municipal coordination and public outreach and participation should be integrated and automated to the fullest extent possible to ensure satisfactory oversight of gas development operations. This includes the use of internet and GIS technologies for geovisualization, database management, and compliance with all regulatory requirements.

One example of internet-based GIS information sharing is the Pennsylvania Department of Environmental Protection's (PA DEP) eMapPA website. PA DEP uses this online application that is updated on a regular schedule and tied to a multitude of databases which track publicly available information (air quality, water quality, mining/reclamation, natural resources, etc.) on a publicly accessible GIS website. (See http://www.emappa.dep.state.pa.us/emappa/viewer.htm).

Recommendation: With regard to regulatory permit tracking, PA DEP has developed an additional tool called Environment, Facility, Application, Compliance Tracking System (eFACTS). PA DEP staff, as necessary, has internal agency access to this database system, cross-referenced by regulatory program, in which permits and permittees may be tracked and updated with regard to permits issued, violations, etc. This information is also available to the public, in a limited format, via the internet at http://www.dep.state.pa.us/dep/efacts/efacts.html. If not already available through the NYS Department Application Review Tracking (DART) system, the development of such a system would be very beneficial for tracking SPDES

HVHF GPs, as well as other state issued permits associated with gas development projects, including dirt/gravel roads, stream crossings, etc. This information should be linked to any web-based GIS application.

Recommendation: Population of a geodatabase may occur through the submission of GIS data by permittees. Permit application packages could and should be front loaded for digital information by requiring permittees to submit GIS data (i.e., shapefiles in an accepted Metadata format) about their project sites. At a minimum, a project boundary on georeferenced state plane coordinate system should be required. This website should also link each project boundary to any online permit tracking system, including the email address of appropriate personnel to whom comments may be submitted.

Recommendation: In addition to sharing GIS data with local governments, NYSDEC should, if it has not already, implement a requirement for municipal notification similar to those commonly referred to in Pennsylvania as Act 14 notices. Pennsylvania permitting processes include requirements for written notifications to be sent to each municipality and county government in which the permitted facility is or will be located under an amendment to the Commonwealth's Administrative Code. These notifications allow 30 days for specific municipal and county comments.

Recommendation: Additional public participation may be solicited by the publication of notices of pending permits in NYSDEC's Environmental Notice Bulletin (ENB). Certain SPDES permitting actions are already included in the monthly ENB; however, it may be beneficial to provide a section specific to those SPDES permits issued for HVHF gas development on the ENB website and linked to the DART system.

Comments on the Draft SPDES HVHF GP

Impacts to surface water quality from gas exploration and extraction activities can occur during the construction of the facility, the operation of the facility, and as a result of inadequate restoration of the facility after operations have ceased. Applying specific performance standards and consistent regulatory oversight through a thorough permitting process is essential to ensuring the prevention of water quality impacts. A comprehensive permitting process should include, but not be limited to, the following considerations:

- Clearly defined permitting process and timelines;
- Sound technical guidelines specific to the activities being permitted;
- Compliance with both State and local regulations prior to final permit approvals;
- Opportunities for public participation, outreach, and comment.

These considerations, as well as a comprehensive evaluation of all potential environmental impacts, are essential to the development of permitting procedures that are adequately protective of environmental resources.

The RDSGEIS notes that certain water resources, such as the New York City and Syracuse drinking water supplies, have been the subject of extensive comment and warrant different regulatory requirements (i.e. a prohibition on drilling). Specifically, the "Department finds that standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing." RDSGEIS at 7-55.

In a paper prepared by Patrick O'Dell, a professional engineer with the National Park Service Geologic Resources Division, Mr. O'Dell noted that "If the public

depends on operators in general to voluntarily use measures such as 'best management practices' to meet an agency's standards of resource protection, the public will be disappointed. This is because operators are sometimes willing to assume more environmental risk in exchange for a reduction in expense or acceleration of project completion."[8]

Given these comments, and that the Department recognizes that "*standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing*," and the Department's decision to preclude HVHF in FAD watersheds (Section 7.1.5), the validity and effectiveness of a self-monitoring GP process for other watersheds cannot be assumed to be protective of water resources, and the SPDES permit and associated regulatory activities must be developed to address these concerns.

In comments provided to the Pennsylvania DEP, Dr. James Schmid[14] PhD made the following recommendations that are directly applicable to NYSDEC regarding the HVHF SPDES permitting process in New York:

a. Place all gas-related permit applications, issued permits, and enforcement actions online in an electronic database accessible by public.
b. Include stream encroachment for pipelines *(in the SPDES permit).*
c. Select a significant number of permit applications for file and on-site audit, to ascertain trends in adequacy of permitting process.
d. Disallow general permits in Exceptional Value and High Quality waters (or in New York, require individual permits for AA or A drinking water streams and T or TS trout streams).
e. Require an inventory for all EV or HQ streams within 500 ft of well pads.

f. Make an attained use determination at every stream proposed for impact that has not been studied.
g. Require disclosure of ALL related facilities in each project application, require disclosure of all land and water disturbances for each well or well pad so that projects do not incorrectly fall below thresholds.
h. Require construction of impermeable holding areas sufficient to contain spills and prevent release outside pad.
i. Require accounting of tree clearing. Provide plans and timetable for reforestation.
j. Gathering lines and water pipelines should follow existing roads rather than new ROWs. New ROWs should be demonstrated to reduce stream/wetland crossings.
k. Distinguish between new stream crossings and those made atop existing culverts.

With these and other previously discussed recommendations in consideration, the following comments are provided with regards to the current Draft HVHF SPDES General Permit:

Comment 1: The Draft HVHF SPDES permit is primarily a compilation of the existing Construction SPDES GP (001) and the Industrial Stormwater GP (002). It has not been significantly modified to address the issues specific to HVHF. Additionally, the Draft HVHF SPDES permit should encompass ALL components of a well project (well pads, access roads, water lines, gathering lines, compressor stations, water withdrawals, transportation of materials, waste management) with considerations specific to HVHF, or clearly provided coordination with other permitting requirements specific to these issues.

Comment2: Given the lack of local land use review, the mapping and data requirements for the SWPPP should be coordinated with the mapping/data

requirements of the Environmental Assessment Form, and all information should be available digitally for access by local government, property owners, and the general public. The RDSGEIS Appendix 5 *Environmental Assessment Form Attachment to Drilling Permit Application* does NOT reflect all site data requirements described in Appendix 6 *Proposed EAF Addendum Requirements for High-Volume Hydraulic Fracturing*.

Comment3: The SPDES HVHF GP should be modified to include construction and stormwater discharges related to gathering lines, compressor stations and compressor station access roads, or to clarify how these activities will be addressed under another permit.

Comment 4: In the absence of more explicit requirements, such as the submission of supporting calculations for BMP design, owners/operators are likely to use a generic narrative for multiple wells, with exception of mapping requirements. It is important that the SPDES HVHF GP requirements for mapping be site specific, comprehensive, at a scale that provides info needed. Generic SWPPPs tend to be ignored.

The following comments are in regard to specific sections of the Draft SPDES HVHF GP as noted.

Part I GENERAL PERMIT COVERAGE AND LIMITATIONS

Comment 5:

Section B.2 Maintaining Water Quality – This section places the burden of identifying a violation of a water quality standard on the Department, as opposed to the permittee. In the Industrial Stormwater GP, the burden of identifying such stormwater discharges is placed on the permittee: "*If there is evidence indicating*

that the stormwater discharges authorized by this permit are causing, have the reasonable potential to cause, or are contributing to an excursion above an applicable water quality standard, the permittee must take appropriate corrective action and notify DEC of corrective actions taken." Similar responsibility should be placed on the permittee for HVHF activities.

Comment 6:

Section C.3 Non-Stormwater Discharges – This section authorizes non-stormwater discharges and adds "uncontaminated discharges from well site dewatering operations" to the list of allowable non-storm discharges. Is this section referring to only de-watering of erosion and sediment control measures in site development or to well drilling material? This should be clarified.

Comment 7:

Section D.2 Activities Which are Ineligible for Coverage under this General Permit – This section precludes the construction of HVHF only on locations where the stream designation is AA or AA-s, **and** there is no impervious cover **and** the slopes are greater than 25% or E / F slope designation. Does this mean that if there is some impervious cover on such a site that HVHF is allowed? Does this mean that all other sites have no limits on slope (unless identified by the applicant as addressed in local land use regulations **and** identified as an objection by local government)? Is disturbance of steep slopes allowed in T streams? Should steep slope disturbance be precluded in proximity to water bodies and wells and identified in setbacks? The RDSGEIS notes in Section 6.1.2 that "*Steep access roads, well pads on hill slopes, and well pads constructed by cut-and-fill operations pose particular challenges, especially if an on-site drilling pad is proposed."* This section should be substantially re-evaluated to preclude or define limits on coverage for steep slopes, etc. in all watersheds. Additionally, the Department should develop specific performance parameters/requirements for coverage of such activities on steep slopes under an Individual Permit for sites not addressed under the GP, rather

than issuing an Individual Permit that is substantially similar to the GP. Additionally, this section should clarify that local land use regulations regarding steep slopes and other environmental constraints apply unless waived by local government.

Comment 8:

Section D.4 Setbacks for Well Pad – These setbacks should reflect further consideration in the RDSGEIS, and include all setbacks discussed and identified in the RDSGEIS and appendices – such as setbacks from private water supply wells and springs, public water supply wells, residences, etc. This section should also clarify where ALL HVHF activities are prohibited (i.e. within 100-year floodplain, within 4,000 feet of unfiltered water supply watersheds, within 2,000 feet of public water supply, etc.).

All setback dimensions should be indicated on the GP mapping requirements.

Additionally, this section should clarify that local land use regulation setbacks also apply unless waived by local government. The permittee should prepare documentation that such land use regulations have been evaluated, and the local government notified if local land use requirements have not been met.

Part II Obtaining General Permit Coverage

Comment 9:

A. Notice of Intent (NOI) Submittal – The applicant is required to submit an NOI form to the Department, and prepare a SWPPP. The SWPPP must be available to the Department (if requested) and maintained on site. This process does not provide for public access and notification (other than the publication in a newspaper, which is easily overlooked by the public).

The public, including immediately adjacent property owners, should have opportunity for notification when such notification is submitted to the Department.

Many local governments have adjacent property owner notification requirements as part of the local zoning and land development process. Since this process does not apply to HVHF, a process of notification to adjacent and potentially impacted property owners should be included in Section II.A. Clarification of the definition of "potentially impacted property owners" requires further consideration in the RDSGEIS. Potentially, notice should be provided to water suppliers, etc.

If coverage under the GP is dependent upon development and implementation of the SWPPP, then the SWPPP must be available for public review upon request. It is likely that most members of the general public would not necessarily know how to request or obtain a copy of the SWPPP. As previously suggested, an on-line database would allow public and Department access to the SWPPP. It is unreasonable to allow the industry to obtain GP coverage without an opportunity for public comment.

Comment 10:

B.2.3.b General Permit Authorization – Given the unique nature of HVHF construction, and the lack of local government review regarding land use disturbance and stormwater management, the permit should impose a time period between preparation and submission of any and all required materials and actual permit coverage. All material should be digitally submitted and all information regarding land disturbance activities should be available and accessible for public review and comment, with a minimum 30-day period for public comment before permit coverage. HVHF practices are different from other industrial practices and coverage under a general permit must provide some process for public review and comment on permit coverage.

Comment 11:

C. Impaired Waters and TMDLs – The RDSGEIS has not provided any documentation or consideration as to whether a general permit is sufficient to prevent further water quality impacts in impaired waters and especially watersheds with TMDLs. A requirement should be imposed for the permit applicant to identify to the Department when the discharge will occur in impaired waters, and what specific additional measures are being implemented to provide protection for the specific pollutants of concern. The Department should maintain specific records and documentation of HVHF activities in impaired waters. Additional monitoring and reporting requirements are warranted in impaired waters, and should be submitted to the Department, not just maintained on site.

Part III – DEVELOPMENT AND ADMINISTRATION OF THE CONSTRUCTION SWPPP

Comment 12:

A.3. Development of the Construction SWPPP – Section 5.1 of the RDSGEIS identifies a number of types of land disturbance activities associated with HVHF including utility corridors (including gathering lines), compressor facilities, and access roads associated with compressor facilities. However, the construction of gathering lines, compressor facilities and the access roads associated therewith is not required to be addressed in the SWPPP. The GP and the required SWPPP contents should be revised to include construction and stormwater discharges related to gathering lines, compressor stations and associated access roads, as well as those facilities currently listed under this section.

Comment 13:

C.1. Disturbance of more than five (5) acres – If phased construction is planned,

with a maximum of five acres disturbed in any phase, the permitting of greater disturbance may be permissible under the SPDES HVHF GP as it is currently written.

Recommendation: The SPDES HVHF GP should be revised to require approval when the soil disturbance activities will result in more than five acres of disturbance at any one time, or more than five acres of disturbance over the life of the project.

Recommendation: The SPDES HVHF GP should be revised to effectively cover all areas not in AA, AA-Special, or FAD areas.

Part IV CONTENTS OF SWPPP

Comment 14:

A. What the Construction SWPPP Must Achieve –The SPDES HVHF GP requires well sites to be *designed to minimize environmental impacts* through the minimization of clearing and grading; and avoidance of sensitive areas such as erodible soils, steep areas, and critical habitats. However, the SPDES HVHF GP does not indicate how the permittee will achieve this.

Recommendation: The SPDES HVHF GP should be revised to clearly indicate how sensitive areas will be identified in permittee submission packages and require the identification to be done so at a mapping scale adequate to clearly identify all potential sensitive areas to ensure clearing and grading will be minimized accordingly. This requirement also applies to setback requirements around waterbodies. (See additional comments under Part IV.C.1. and Part IV.A.)

Comment 15:

B.1.b. and e. Effluent Limitation Requirements – The SPDES HVHF GP requires compliance with erosion and sediment controls to *minimize the discharge of pollutants,* specifically the control of stormwater and sediment discharges, but does not require supporting calculations to be submitted.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit calculations supporting any claim of compliance with mandatory control of stormwater, sediment, or other pollutant discharges.

Comment 16:

C.1.b. Erosion and sediment control components - The SPDES HVHF GP requires a site map/construction drawing(s) that include information vital to erosion and sediment control considerations, including wetlands, potentially affected surface waters, existing and final slopes, and location(s) of stormwater discharges. However, there is no maximum scale identified for this requirement. It is possible that sensitive features may be overlooked and steep slopes unidentified if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification of features to be avoided or protected during construction.

Comment 17:

C.1.i. Erosion and sediment control components – The inspection schedule, as well as the corresponding inspection reports should be made available with the SWPPP for Department access. At a minimum, the inspection schedule should be made available to the public and include a Department contact where concerns may be reported.

Comment 18:

D.1.b. Post-construction stormwater management practice component - The SPDES HVHF GP requires a well site map/construction drawing(s) that include information vital to post-construction stormwater management practice evaluation,

including the specific location and size of each post-construction stormwater management practice. However, there is no maximum scale identified for this requirement. It is possible that the regulatory review of post-construction stormwater management practices may be inadequate if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification and evaluation of proposed post-construction stormwater management practices.

Comment 19:

D.1.e. Post-construction stormwater management practice component - The SPDES HVHF GP requires a hydrologic and hydraulic analysis for all structural components of the stormwater management control system. However, the SPDES HVHF GP does not require supporting calculations to be submitted in support of these analyses. Without supporting calculations, regulators will be limited in the ability to effectively review the appropriateness of the proposed system.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit calculations supporting the hydrologic and hydraulic analysis of all structural components of the proposed stormwater management control system. All calculations and information should be available to the public upon request.

Comment 20:

D.1.f. Post-construction stormwater management practice component – The SPDES HVHF GP requires a detailed summary of the sizing criteria that were used to design all post-construction stormwater management practices *including calculations* to be submitted with the SWPPP. The SPDES HVHF GP requires the summary to address, at a minimum, the required design criteria from applicable chapters of the 2010 New York State Stormwater Management Design Manual.

However, the SPDES HVHF GP does not indicate that the calculations are site specific. Given the variability of site conditions throughout any given project, it is essential that the post-construction stormwater management practices be designed to address the unique considerations of both the site conditions and the functional practicality of any proposed post-stormwater management practice.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit site-specific calculations supporting the design of all proposed stormwater management practices to ensure they are appropriate for site-specific conditions.

Comment 21:

E. Enhanced Phosphorous Removal Standards – The SPDES HVHF GP requires post-construction stormwater management practices to be designed in conformance with the Enhanced Phosphorous Removal Standards included in the 2010 New York State Stormwater Design Manual. However, the SPDES HVHF GP does not require permittees to submit documented implementation of this requirement.

Recommendation: The SPDES HVHF GP should be revised to require permittees to document the implementation of the Enhanced Phosphorous Removal Standards within the SWPPP as part of their permit application package.

Part V-CONSTRUCTION OF WELL SITE – INSPECTION, MAINTENANCE, AND RECORDKEEPING REQUIREMENTS

Comment 22:

D. Recordkeeping – The SPDES HVHF GP requires all inspection reports to be maintained on the *well site* with the *Construction SWPPP*. Without a requirement to submit inspection reports or, at a minimum, a list of violations and corrective actions required, to the Department, the inspection reports may not serve their

intended purpose. Regardless of limitations to staff and funding, the Department should maintain responsibility for ensuring compliance with applicable regulations. The utilization of *qualified inspectors* is only one part of ensuring compliance and should be supplemented with quality control checks by the Department, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of inspection reports or, at a minimum, a list of violations and correctives actions required, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of inspection documents to ensure compliance is being achieved.

Part VI CONSTRUCTION PHASE COMPLETION

Comment 23:

B. Inspections – The SPDES HVHF GP requires from qualified inspectors, by signature, a statement certifying achievement of final site stabilization. However, the SPDES HVHF GP does not require any documentation supporting this certification.

Recommendation: The SPDES HVHF GP should be revised to require documentation, specifically time/date-stamped digital photographs, to support certification of final stabilization.

Part VII HVHF SWPP

Comment 24:

Part VII General comment – Would an applicant be permitted to submit one

generic document to be applied at multiple sites? If so, it is unlikely that all relevant issues will be adequately addressed.

Recommendation: The SPDES HVHF should be revised to require a site-specific SWPPP as described in previous comments to ensure adequate protection and mitigation measures are proposed.

Comment 25:

A.5. Development of the HVHF SWPPP – The SPDES HVHF GP requires the HVHF SWPPP to be developed by someone knowledgeable in the principles and practices of stormwater management and groundwater protection associated with the HVHF Phase and the Production Phase. The SPDES HVHF GP specifically mentions a Professional Engineer. However, the principles and practices of groundwater protection are often best performed by a Professional Hydrogeologist.

Recommendation: The SPDES HVHF GP should be revised to reference the appropriate professional disciplines necessary to adequately address both stormwater management (Professional Engineer) and groundwater protection (Professional Hydrogeologist).

Comment 26:

A.11 Development of the HVHF SWPPP – The SPDES HVHF GP allows the Department to issue an immediate stop work order upon a finding of significant non-compliance of the HVHF SWPPP or violation of the GP.

Recommendation: The ability to issue a stop-work order is a great option for the Department and should be supplemented by random quality control reviews performed as described in previous comments.

Part VIII HVHF OPERATION REQUIREMENTS

Comment 27:

A.1. and 2. General Requirements – The SPDES HVHF GP requires owners and operators to develop and evaluate alternatives for HVHF Phase fluid additives and to maintain a list of all HVHF Phase fluid additives on-site. The Department must make clear that propriety information must not be excluded from this list.

Comment 28:

A.4. General Requirements – The SPDES HVHF GP requires qualified inspectors to sign a statement certifying achievement of final site stabilization prior to initiating the HVHF Phase. However, the SPDES HVHF GP does not require any documentation supporting this certification.

Recommendation: The SPDES HVHF GP should be revised to require documentation, specifically time/date-stamped digital photographs, to support certification of final stabilization.

Comment 29:

A.6. General Requirements – The SPDES HVHF GP requires Department inspector verification of partial site reclamation. However, the SPDES HVHF GP does not address the procedures necessary if partial site reclamation is not sufficient.

Recommendation: The SPDES HVHF GP should be revised to detail the process for addressing sites where the requirements for partial site reclamation are insufficient.

Part IX CONTENTS OF THE HVHF SWPPP

Comment 30:

A.2. HVHF General SWPPP Requirements – The SPDES HVHF GP requires a site map that includes information critical to adequately review and evaluate the HVHF

SWPPP. Specifically, the SPDES HVHF GP cites a *USGS quadrangle or other map.* While a USGS quadrangle map may be adequate for showing general site location, it is not appropriate for showing detailed information. It is possible that the regulatory review of the HVHF SWPPP may be inadequate if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification and evaluation of proposed post-construction stormwater management practices. Specifically, this section of the SPDES HVHF GP should be revised as follows:

b. Directions of stormwater flow should be shown on a contoured map with contours shown at minimum 5-ft intervals.

e. The scale for maps showing the locations of items listed in this section should be mapped at an appropriate defined scale (e.g. 1"=50' maximum). This section should also include the location of gathering lines.

g. Drainage area maps and stormwater outfall locations should be submitted on a separate stormwater map, attached to the site map, to ensure correct documentation.

i. The procedure for determining areas with significant potential for causing erosion should be defined or, if already defined in other documents, referenced.

Comment 31:

A.4. HVHF General SWPPP Requirements – This section requires the name, classification, and distance from the nearest edge of the well pad to the nearest receiving water(s). Submission of this information in narrative form may be sufficient, but an appropriately scaled map with labeled features would also provide an easily-verifiable document.

Recommendation: The SPDES HVHF GP should be revised to require a map showing the name, classification, and distance from the nearest edge of a well pad to the nearest receiving water(s) at a legible scale.

Comment 32:

A.7. HVHF General SWPPP Requirements – The inclusion of gravel is important when considering the total imperviousness of the well site. The compaction of subsoils and clogging with fine sediment within gravel areas has been shown to function as an impervious surface with regard to stormwater runoff.

Comment 33:

A.7. HVHF General SWPPP Requirements – This section includes an equation for estimating the total imperviousness of a well site as:

> Area of Roofs + Area of Paved and Other *Impervious* Surfaces, including gravel and roads = Total Area of *Well site.*

This equation should be revised as follows:

> Area of Roofs + Area of Paved and Other *Impervious* Surfaces, including gravel and roads = Total Impervious Surface Area of *Well site.*

Comment 34:

A.11. HVHF General SWPPP Requirements – The SPDES HVHF GP requires a summary of discharge sampling data to be maintained on the well site. Without a requirement to submit sampling data to the Department, it is possible that discharges in violation of the SPDES HVHF GP may be overlooked. Regardless of limitations to staff and funding, the Department should maintain responsibility for compliance and enforcement through quality control checks.

Recommendation: Quality control checks should be performed by the Department and facilitated by the submission of sampling data to the Department electronically. Checks should then be verified through cross-checking submitted sampling data

against Department-collected sample data. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Comment 35:

A.13. HVHF General SWPPP Requirements – In addition to identifying the proposed sources or any water to be used at the well site, an estimate of proposed volume to be withdrawn from each source will assist in tracking any pollutants found in that water.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit estimated volumes to be withdrawn from each identified water source.

Comment 36:

A.16. HVHF General SWPPP Requirements – The SPDES HVHF GP requires the HVHF SWPPP to include a description of stormwater management controls appropriate for the *well site*. However, the SPDES HVHF GP does not indicate that this description will include site specific sizing calculations. Given the variability of site conditions throughout any given project, it is essential that stormwater management controls be designed to address the unique considerations of both the site conditions and the functional practicality thereof.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit site specific sizing calculations supporting the design of all proposed stormwater management controls to ensure they are appropriate for site-specific conditions. Site-specific stormwater management controls should be evaluated for design and performance through inspection reporting and quality control as described in previous comments.

Comment 37:

A.18.k. HVHF General SWPPP Requirements – The SPDES HVHF GP requires the HVHF SWPPP to include information about partial site reclamation, including a requirement that reclaimed areas be seeded and mulched after topsoil replacement and reestablishment of vegetative cover. Standards for acceptable seeding, maintenance of seeded areas, and soil restoration should be defined in order to ensure reclamation, revegetation, and continued stabilization are achieved.

Recommendation: The SPDES HVHF GP should be revised to include by definition or reference standards for acceptable seeding, maintenance of seeded areas, and soil restoration.

Comment 38:

B.1.p. Required Non-Structural BMPs - The SPDES HVHF GP requires the owner or operator to use absorbents for dry cleanup whenever possible. However, the SPDES HVHF GP does not address the disposal of used absorbents.

Recommendation: The SPDES HVHF GP should be revised to address the disposal of used absorbents in accordance with NYS and EPA guidelines.

Comment 39:

C. Required Structural BMPs – The SPDES HVHF GP requires the HVHF SWPPP to "describe the traditional stormwater management practices…that currently exist or that are planned." However, the SPDES HVHF GP does not require calculations supporting the capacity of existing stormwater management practices to manage additional stormwater from newly constructed well sties, nor does the SPDES HVHF GP require supporting calculations for design of proposed stormwater management practices. Without a thorough review prior to issuance of the GP, it is possible that stormwater management practices will be inadequate to effectively address stormwater runoff from well sites.

Recommendation: - The SPDES HVHF GP should be revised to require the submission of calculations supporting the capacity of existing stormwater management practices and the design of proposed stormwater management practices to effectively manage stormwater runoff resulting from the construction and operation of a well site.

Part X ACTIVITIY-SPECIFIC STRUCTURAL AND NON-STRUCTURAL BMPs AND BENCHMARK MONITORING REQUIREMENTS

Comment 40:

A.5. General – The SPDES HVHF GP states that "if the [HVHF] activities are conducted for less than one (1) calendar year, all stormwater monitoring requirements must be satisfied during the period of activity. If no qualifying storm event occurs during the period of activity, or no qualifying storm event results in a *discharge*, monitoring requirements must be completed during the first qualifying storm that results in a *discharge*." However, the SPDES HVHF GP does not define the term "qualifying storm event." To ensure adequate monitoring of stormwater resulting from HVHF activities, the monitoring and sampling requirements must be clearly defined in order for permittees to satisfy the conditions of the permit.

Recommendation: The SPDES HVHF GP should be revised to include a clear definition of the term "qualifying storm event."

Comment 41:

D. Vehicle and equipment cleaning areas – The SPDES HVHF GP states that "discharge of vehicle and equipment wash waters … are not authorized by the SPDES HVHF GP and must be covered under a separate SPDES permit or discharged to a sanitary sewer in accordance with applicable industrial pretreatment requirements or transported off-site for proper disposal." The intent of the SPDES HVHF GP was to streamline and condense the permitting process for HVHF

activities. Requiring a separate permit for the discharge of vehicle and equipment wash waters seems redundant in light of the ability of the SPDES HVHF GP to cover all other HVHF activities.

Recommendation: The SPDES HVHF GP should be revised to incorporate all the provisions necessary to meet New York State permitting requirements within a single permit, including the provisions necessary to authorize discharges from vehicle and equipment wash waters or require off-site transportation for disposal.

Comment 42:

J. Piping/conveyances – The SPDES HVHF GP requires the HVHF SWPPP to include and describe measures that prevent or minimize the contamination of surface runoff from spills and leaks from piping/conveyance systems used for transferring "fresh water, *flowback* water, *production brine*, well *stimulation* water, sanitary, and other wastewaters." However, the SPDES HVHF GP does not address this requirement for piping/conveyance systems used for transferring the gas produced by each well site. Failure to address the piping/conveyance systems used for gas transmission may result in inadequate protection of surface waters in the event of a leak or spill of gas.

Recommendation: The SPDES HVHF GP should be revised to address all piping/conveyances, including gas transmission systems.

Comment 43:

J.2.p. Piping/conveyances – The SPDES HVHF GP states, "pipelines buried under stream crossings shall be buried below the scouring depth and may require other permits." The SPDES HVHF GP does not require the submission of supporting calculations for determination of scour depth, nor does it clearly define the conditions under which "other permits" may be required. Furthermore, it seems that NYSDEC does not require stream crossing permits for activities other than silviculture. This lack of oversight may result in significant impacts to surface

waters due to the potential thousands of crossings at headwater streams to facilitate HVHF activities.

Recommendation: The SPDES HVHF GP should be revised to require submission of calculations supporting the determination of scour depth for the placement of buried pipeline stream crossings.

Recommendation: The SPDES HVHF GP should be revised to clearly define which "other permits" may be required and the conditions under which those "other permits" are applicable.

Recommendation: NYSDEC should examine current stream crossing requirements and develop more robust regulations to ensure proposed crossings are constructed and maintained appropriately and do not impact water quality.

Comment 44:

M. Freshwater Surface Impoundments and Reserve Pits – The SPDES HVHF GP states, "a closed-loop tank system must be used instead of a reserve pit to manage drilling fluids and cuttings for any of the following: a) horizontal drilling in the Marcellus Shale unless an acid rock drainage mitigation plan for onsite burial of such cuttings is approved by the Department; and; b) any drilling requiring cuttings to be disposed of off-site, as provided in Part 360 of this Title, including at a landfill." However, the SPDES HVHF GP does not define an "acid rock drainage mitigation plan." The SPDES HVHF GP also does not clearly identify the reference to Part 360 in section (b), above.

Recommendation: The SPDES HVHF GP should be revised to include a section defining an "acid rock drainage mitigation plan" which includes the conditions under which the plan must be developed, the issues which the plan must address (including any necessary supporting calculations), and the contents which must be included in the plan.

Recommendation: The SPDES HVHF GP should be revised to clearly identify the statute included in part (b) of this section which references the off-site disposal of cuttings.

Part XII HVHF PHASE MONITORING

Comment 45:

A. Schedule for Monitoring – The SPDES HVHF GP requires a schedule for visual monitoring and examination of stormwater discharges at each outfall after each qualifying storm that must document observed color, odor, clarity, floating solids, settled solids, suspended solids, foam, and oil sheen. However, the SPDES HVHF GP does not require sampling, even if the visual observations indicate the presence of pollutants.

Recommendation: The SPDES HVHF GP should be revised to clearly define sampling requirements. At a minimum, sampling and laboratory testing should be required if a visual examination indicates the presence of pollutants.

Comment 46:

A. Schedule for Monitoring – The SPDES HVHF GP requires visual examination documents to be maintained on the well site. Also, the SPDES HVHF GP does not require photographic documentation to support visual examination reports. The Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of visual examination reports, including photos, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be

accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of visual examination documents to ensure compliance is being achieved.

Comment 47:

A. Schedule for Monitoring – The SPDES HVHF GP states, "all samples (except snowmelt samples) must be collected from the *discharge* resulting from a storm event that is greater than 0.1 inches in magnitude and that occurs at least seventy-two (72) hours from the previously measurable (greater than 0.1 inch rainfall) storm event. The 72-hour storm interval is waived if the preceding measurable storm did not result in a stormwater *discharge* (e.g., a storm event in excess of 0.1 inches may not result in a stormwater *discharge* at some facilities)." Is this the intended definition of "qualifying storm event?"

Comment 48:

A. Schedule for Monitoring – The SPDES HVHF GP states, "if a visual examination was performed and the storm event was later determined not to be a measurable (greater than 0.1 inch rainfall) storm event, the visual examination should still be included in the *HVHF SWPPP* records." The inclusion of all visual examination reports in the HVHF SWPPP record should be required.

Recommendation: The SPDES HVHF GP should be revised to state, "if a visual examination was performed and the storm event was later determined not to be a measurable (greater than 0.1 inch rainfall) storm event, the visual examination must still be included in the *HVHF SWPPP* records."

Comment 49:

A.3.c. Schedule for Monitoring – This section of the SPDES HVHF GP requires samples to be analyzed within ten calendar days after they have been collected.

This information may be more logically located in section A.10.b. which discusses collection and analysis of samples.

Recommendation: The SPDES HVHF GP should be revised to move the above referenced requirement for analysis of samples from Part XII.A.3.c. to Part XII.A.10.b.

Comment 50:

A.3.d. Schedule for Monitoring – This section of the SPDES HVHF GP states, "the benchmark concentrations do not constitute direct numeric effluent limitations and, therefore, an exceedance is not a general permit violation." What is the purpose of benchmark monitoring if exceedance of the benchmark concentrations listed in Part X of the SPDES HVHF GP do not result in a general permit violation?

Recommendation: The SPDES HVHF GP should be revised to omit this sentence from the document. Exceeding benchmark concentrations should immediately result in a violation of the GP to ensure proper corrective action is taken to protect water quality.

Comment 51:

A.3.f. Schedule for Monitoring – The SPDES HVHF GP requires benchmark monitoring results to be documented and maintained on the well site. The Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of benchmark monitoring results, including corrective actions needed, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should

also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of benchmark monitoring documents to ensure compliance is being achieved.

Comment 52:

A.10.b. Schedule for Monitoring – The SPDES HVHF GP states that "sampling requirements must be assessed on an outfall-by-outfall basis." However, there are no criteria upon which sampling requirements are to be assessed. The SPDES HVHF GP also fails to identify the party responsible for directing sampling requirements at each outfall. Sampling requirements should be directed by NYSDEC guidance criteria, to include frequency of collection and analysis requirements.

Recommendation: The SPDES HVHF GP should be revised to clearly identify the Department as the party responsible for directing sampling requirements at each outfall.

Recommendation: The NYSDEC should develop guidance criteria for sampling requirements for HVHF activities. This guidance criteria should address the conditions under which sample collection is required (i.e., when a visual examination indicates the presence of pollution), location of sample collection, frequency of sample collection, and laboratory analysis requirements for collected samples.

Recommendation: The SPDES HVHF GP should be revised to require sampling in accordance with NYSDEC guidance criteria, to include frequency of collection and analysis requirements.

Comment 53:

A.10.b. Schedule for Monitoring – This section of the SPDES HVHF GP does not reference the ten-day time limit for analysis of collected samples.

Recommendation: This section of the SPDES HVHF GP should be revised to include reference to the ten-day time limit for analysis of collected samples included in Part XII.A.3.c.

Comment 54:

A.10.c. Schedule for Monitoring – This section of the SPDES HVHF GP requires owners/operators to provide the date and duration of sampled storm events, rainfall measurements or estimates (in inches) of the storm event that generated the sampled runoff, time between storm events greater than 0.1 inch, and an estimate of volume sampled. A rain gauge/weather station should be required to ensure rainfall greater than 0.1 inch is accurately recorded. This will also ensure visual examination and sampling is completed for events greater than 0.1 inch.

Recommendation: The SPDES HVHF GP should be revised to require rainfall measurements and remove references to rainfall estimates to ensure monitoring and sampling in compliance with the conditions of the permit.

Part XIII HVHF PHASE REPORTING

Comment 55:

A. Discharge Monitoring Reports (DMR) – The SPDES HVHF GP requires the results of laboratory analysis of samples to be submitted to the Department on preprinted DMRs within ten days of their receipt. The required formatting of DMRs lends itself very easily to standardization for electronic submission to the Department, which would allow for faster submission and reduce the costs incurred by both the Department and permittees by eliminating unnecessary paper and paperwork. Furthermore, the Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of DMRs, in approved format via online forms, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of benchmark monitoring documents to ensure compliance is being achieved.

Part XIV MONITORING FOR THE PRODUCTION PHASE AND TEMPORARY SUSPENSION OF THE HVHF PHASE

Comment 56:

A. Schedule for Monitoring – Please see comments 45, 46, 49, 50, 51, 52, 53, and 54, and the corresponding recommendations as they apply to this section of the SPDES HVHF GP.

Part XVI PRODUCTION PHASE REPORTING

Comment 57:

A. Discharge Monitoring Reports (DMR) – Please see comment 55 and the corresponding recommendation as it applies to this section of the SPDES HVHF GP.

Part XXI. STANDARD GENERAL PERMIT CONDITIONS

Comment 58:

F. Duty to Provide Information – The SPDES HVHF GP states, "the NOI, SWPPP and inspection reports required by this general permit are public documents that the *owner or operator* must make available for review and copying by any person within five (5) business of the *owner or operator* receiving a written request by any such

person to review the NOI, SWPPP or inspection reports. Copying of documents will be done at the requester's expense." Many HVHF well sites prohibit access by the general public, and all of the public documents indicated are required by the SPDES HVHF GP to be kept on the well site. In order to expedite requests and eliminate man-hours necessary to escort individuals through restricted areas, as well as provide for the recommendations above, the Department should require the electronic submission of all public documents. These documents should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Recommendation: The SPDES HVHF GP should be revised to allow for the electronic submission of all public documents. These documents should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Attachment A

Technical Information in support of comments:

1. Sediment Loads from Gravel Roads

   The Pennsylvania Center for Dirt and Gravel Road Studies provides information on measures to maintain gravel roads in a manner to reduce the discharge of pollutants and protect water quality. Penn State's Center for Dirt and Gravel Road Studies (Center) recently completed a research project for the Chesapeake Bay Commission (Scheetz, Summary Statement) that begins to quantify sediment production from gravel roads and sediment reductions from several commonly used practices. This study found that:

   > **Runoff Rates from Existing Roads:**
   > *"The five "existing condition" tests done for this study found sediment production rates ranging from 0.7-12.2 pounds of sediment runoff in a single 30 minute, 0.55 inches simulated rainfall. The 0.7 pound event was generated from a flat narrow farm lane with grass growing between the wheel tracks. The 12.2 pound event was generated from a wider, mixed limestone/clay road at a 4-5% slope. This highlights the great variability in erosion rates based on specific site conditions. Using the average sediment runoff rate of 5.6 pounds per event, a single 30 minute 0.55 inch rain event moving across Pennsylvania can be conservatively expected to generate over 3,000 tons* of sediment form the State's 20,000+ miles of public unpaved roads".*

   This research supports that gravel roads can be a significant source of pollutants such as sediment. As discussed in several comments, there is a need for the RDSGEIS to estimate the cumulative impact of gravel road development as a result of HVHF activity.

2. **Water Quality Impacts from Gas Drilling Activities**

   In 2005, the U.S. Environmental Protection Agency (U.S. EPA) awarded a grant to the City of Denton, Texas, to monitor and assess the impact of gas well drilling on stormwater runoff. The results of this effort were published in December 2007

in a report titled "Demonstrating the Impacts of Oil and Gas Exploration on Water Quality and How to Minimize These Impacts Through Targeted Monitoring Activities and Local Ordinances." With regards to the discharge of sediment during construction, this study determined that:

> *"Gas well sites have the potential to produce sediment loads comparable to traditional construction sites.*
>
> - *Total suspended solids (TSS) and turbidity event mean concentrations (EMC = pollutant mass / runoff volume) at gas sites were significantly greater than at reference sites (the median TSS EMC at gas sites was 136 times greater than reference sites).*
>
> - *Compared to the median EMCs of storms sampled by Denton near one of their outfalls, the gas well site median EMC was 36 times greater.*
>
> - *Gas site TSS EMCs ranged from 394 to 9898 mg/l and annual sediment loadings ranged from 21.4 to 40.0 tonnes/hectare/year (tonne = 1000 Kg; hectare = 10,000 square meters), and were comparable to previous studies of construction site sedimentation".*

This study concludes that "Gas well sites have the potential to negatively impact surface waters due to increased sedimentation rates." (US EPA ID No. CP-83207101-1, page 2).

In addition to the well pad site, roads that are constructed, widened, or altered for vehicle access to and from the well pad site can be a source of sediment and pollutants during both construction and operation. The U.S. EPA Publication "Erosion, Sediment and Runoff Control for Roads and Highways" (EPA-841-F-95-008d) states that:

> Runoff controls are essential to preventing polluted runoff from roads, highways, and bridges from reaching surface waters. Erosion during and after construction of roads, highways, and bridges can contribute large amounts of sediment and silt to runoff waters, which can deteriorate water quality and lead to fish kills and other ecological problems.
>
> Heavy metals, oils, other toxic substances, and debris from construction traffic and spillage can be absorbed by soil at construction sites and carried with runoff water to lakes, rivers,

and bays. Runoff control measures can be installed at the time of road, highway, and bridge construction to reduce runoff pollution both during and after construction. Such measures can effectively limit the entry of pollutants into surface waters and ground waters and protect their quality, fish habitats, and public health.

This publication (EPA-841-F-95-008d) identifies a number of pollutant types and sources related to Roads and Highways, as identified in Table 1.

Table 1. Typical pollutants found in runoff from roads and highways.

Erosion, Sediment and Runoff Control for Roads and Highways | Polluted Runoff | US EPA

	Pollutant	**Source**
Sedimentation	Particulates	Pavement wear, vehicles, the atmosphere and maintenance activities
Nutrients	Nitrogen & Phosphorus	Atmosphere and fertilizer application
Heavy Metals	Lead	Leaded gasoline from auto exhausts and tire wear
	Zinc	Tire wear, motor oil and grease
	Iron	Auto body rust, steel highway structures such as bridges and guardrails, and moving engine parts
	Copper	Metal plating, bearing and brushing wear, moving engine parts, brake lining wear, fungicides & insecticides
	Cadmium	Tire wear and insecticide application
	Chromium	Metal plating, moving engine parts and brake lining wear
	Nickel	Diesel fuel and gasoline, lubricating oil, metal plating, bushing wear, brake lining wear and asphalt paving
	Manganese	Moving engine parts
	Cyanide	Anti-caking compounds used to keep deicing salt granular
	Sodium, calcium & chloride	Deicing salts
	Sulphates	Roadway beds, fuel and deicing salts
Hydrocarbons	Petroleum	Spills, leaks, antifreeze and hydraulic fluids and asphalt surface leachate

References

1. Center for Rural Pennsylvania "the Impact of Marcellus Gas drilling on Rural Drinking Water Supplies", October 2011.

2. Entrekin, Sally, et al, "Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters", From Frontiers in Ecology 2011; 9(9): 503-511, Oct 2011.

3. Etowah Aquatic Habitat Conservation Plan "Utility Stream Crossings Policy", July 13, 2006.

4. Handlerof, Stephanie; League of Women Voters of Indiana "Marcellus Shale Natural Gas Extraction Study 2009-2010 Study Guide V: Regulation and Permitting of Marcellus Shale Drilling", League of Women Voters of Pennsylvania, 2010.

5. Kaplan, Louis, et al "Protecting Headwaters: The Scientific Basis For Safeguarding Stream And River Ecosystems, A Research Synthesis from the Stroud Water Research Center " 2008.

6. Leopold, Luna B.; "A View of the River", Harvard University Press, Cambridge, MA, 1994.

7. NYDEC "Stream Crossings Protecting and Restoring Stream Continuity" web page at http://www.dec.ny.gov/permits/49060.html.

8. O'Dell, Patrick M., Professional Engineer in Petroleum Engineering, National Park Service Geologic Resources Division, "Potential for Development of Natural Gas Exploratory Wells to Adversely Affect Water Resources of the Delaware River Basin", Nov 23, 2010.

9. Reid, Scott M. and Paul G. Anderson "Effects of Sediment released During Open-cut Pipeline Water Crossings, Canadian water Resources Journal Vol. 24, No 3, 1999.

10. Scheetz, Dr. Barry E. and Steven M. Bloser; Center for Dirt and Gravel Road Studies, The Pennsylvania State University, University Park, PA 16802; "Environmentally Sensitive Maintenance Practices for Unpaved Roads: Sediment Reduction Study" Prepared for Chesapeake Bay Commission c/o Senate of Pennsylvania G-05 North Office Building Harrisburg, PA 1712, FINAL REPORT June 30, 2008, Revised August 29, 2008 and Summary Statement

11. United States Environmental Protection Agency "Erosion, Sediment and Runoff Control for Roads and Highways", Office of Water (4503F) EPA-841-F-95-008d, December 1995

12. United States Environmental Protection Agency, Final Report for Catalog of Federal Domestic Assistance Grant Number 66.463 Water Quality Cooperative Agreement for Project Entitled "Demonstrating the Impacts of Oil and Gas Exploration on Water Quality and How to Minimize these Impacts Through Targeted Monitoring Activities and Local Ordinances" and "Summary of the Results of the Investigation Regarding Gas Well Site Surface Water Impacts", ID No. CP-83207101-1, Kenneth E. Banks, Ph.D. Manager, Division of Environmental Quality and David J. Wachal, M.S. Water Utilities Coordinator

13. United States Environmental Protection Agency, Wadable stream assessment: a collaborative survey of the nation's streams, 2006. EPA 841-B-06-002.

14. Letter from James A. Schmid, PhD, Schmid & Company Consulting Ecologists to Scott E. Walters, Chief General Permits Bureau of Waste Management PaDEP, 8 November 2011.

Attachment 7

The Louis Berger Group, Inc.

THE Louis Berger Group, INC.
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Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Review Comments on the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations (Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560)

1.0 Introduction

The Louis Berger Group Inc. (LBG) reviewed the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS), the proposed Environmental Assessment Form (EAF) and EAF Addendum (RDSGEIS Appendices 5 and 6), the proposed Supplemental Permit Conditions (RDSGEIS Appendix 10) and the proposed High-Volume Hydraulic Fracturing (HVHF) regulations (Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560) for the following topics:

- Noise (RDSGEIS Sections 2.4.13 and 6.10)
- Ground-borne noise and vibration (impacts not addressed in the RDSGEIS)
- Visual impacts (RDSGEIS Sections 2.4.12 and 6.9)
- Land use (impacts not addressed in the RDSGEIS)
- Transportation (RDSGEIS Sections 2.4.14 and 6.11)
- Community character (RDSGEIS Sections 2.4.15 and 6.11)
- Cultural resources (impacts not addressed in the RDSGEIS).
- Aquatic Ecology (RDSGEIS Sections 6.1.1.2, 6.1.1.3 and 6.1.1.4).

For each topic, the following sections address the sufficiency of the RDSGEIS impact analyses and proposed mitigation measures in meeting State Environmental Quality Review Act (SEQRA--6 NYCRR Part 617) requirements. The comments also identify specific improvements and best practice approaches that the New York State Department of Environmental Conservation (NYSDEC) could use to resolve the deficiencies identified and minimize the environmental impacts of High-Volume Hydraulic Fracturing (HVHF) and related development in New York.

2.0 Noise

2.1 Construction Impacts

The 2011 RDSGEIS quantitative construction noise assessment uses information from the Federal Highway Administration's Road Construction Noise Model to estimate noise

levels at various distances from the construction site and represents a substantial improvement over the qualitative analysis in the 2009 Draft Supplemental Generic Environmental Impact Statement (DSGEIS). For quiet rural areas, the results show that construction activities would result in significant adverse impacts under NYSDEC criteria (increase of 6 dBA (A-weighted decibels) or more over existing conditions) at distances exceeding 2,000 feet.

The RDSGEIS provides the requisite construction noise analysis, but fails to appropriately evaluate and discuss the significance of the model results. Instead, a one sentence conclusion is provided: "Such levels would not generally be considered acceptable on a permanent basis, but as a temporary, daytime occurrence, construction noise of this magnitude and duration is not likely to result in many complaints in the project area."

Contrary to this statement, there is no regulatory requirement that access road construction and site preparation be limited to daytime hours. To mitigate this significant adverse impact, a prohibition on nighttime construction should be included in the HVHF regulations or supplemental permit conditions to avoid annoyance and sleep disturbance of nearby residences, along with other construction noise control best practices (See Section 2.6 infra).

Further, the assertion in the RDSGEIS that construction noise impacts are "temporary" ignores the likelihood of large number of wells and pads being concentrated in certain areas, as well as construction noise from related infrastructure development (pipelines, compressors, etc.). The cumulative construction noise impact has not been addressed.

In addition, noise-related complaints are not the appropriate basis for drawing conclusions about the significance of noise impacts under SEQRA because people (and wildlife) can be adversely affected by noise, but choose not to report it. NYSDEC should evaluate the significance of the construction noise impacts in relation to the duration, quality (tonal purity), time of day and year, background noise present, distance to the source, familiarity with the noise and other factors such as the setting. Studies have shown that each listener's subjective perception of appropriateness of a noise in a particular setting can be just as important to annoyance as the objective sound level.[1] Given the rural context of the majority of the areas where natural gas development is expected to occur, many residents and visitors to these areas would find heavy construction activity noise to be out of place and annoying. Construction noise adjacent to parks and other sensitive land areas where natural quiet is expected would be especially problematic and would contribute to adverse economic impacts not accounted

[1]See: Blauert, J. 1986. "Cognitive and Aesthetic Aspects of Noise Engineering." In *Proceedings of Inter-Noise 86, Cambridge, Massachusetts, July 21–23*, volume 1, 5–13.

Kuwano, S., S. Namba, and H. Miura 1989 "Advantages and Disadvantages of A-weighted Sound Pressure Level in Relation to Subjective Impression of Environmental Noises."*Noise Control Engineering Journal* 33:107–115.

Carles, J.L., I. Lopez Barrio, J.V. de Lucio 1999 "Sound Influence on Landscape Values."*Landscape and Urban Planning* 43:191–200.
Ozawa, K., S. Ohtake, Y. Suzuki, and T. Sone 2003 "Effects of Visual Information on Auditory Presence," Acoustical Letter to Acoustical Science and Technology, 24(2), 97-99.

for in the 2011 RDSGEIS by making areas where gas development is occurring less attractive to visitors.[2]

2.2 Drilling and Fracturing Impacts

2.2.1 Failure to Analyze Multi-Well Pad Impacts

The general approach used in the RDSGEIS quantitative noise impact assessment is reasonable and consistent with the methodology recommended in NRDC's comments on the 2009 DSGEIS for evaluation of the impacts of drilling and fracturing of one horizontal well. However, it fails to analyze the impacts of multi-well pads, which is the primary form of development anticipated. Table 6-59 in the RDSGEIS presents the duration of various construction and operational phases for one well. Each well is estimated to take 28-35 days to drill, while fracturing is assumed to take up to five days. Since drilling or fracking of multiple wells is likely to occur simultaneously, the combined noise levels would be higher than those reported for a single well in the RDSGEIS.

The failure of the RDSGEIS to provide a noise impact assessment for the simultaneous drilling and fracturing of multiple wells is especially problematic because it is inconsistent with the scenario developed for the analysis of transportation impacts (page 6-305). The result of this inconsistency is that the noise impacts of drilling and fracturing are underestimated and do not reflect a reasonably foreseeable worst-case development scenario. The multi-pad horizontal well development scenario in the transportation section of the RDSGEIS assumed three rigs would be operated simultaneously over a 120 day period and that each rig would drill four wells (for a total of 12 wells at the site). With three rigs in operation at the same time, the combined noise level at a distance of 50 feet would be approximately 84 dBA, not 79 dBA as reported for one rig in the RDSGEIS (Table 6.56- Rotary Air Well Drilling).[3]

With respect to the fracturing phase, the RDSGEIS wording is unclear, but appears to suggest sequential fracturing (one well being fractured at a time for a total of 60 days of fracturing noise impacts). The RDSGEIS states "fracturing and completion of the four wells occurs sequentially and tanks are brought in once for all four wells" (page 6-305). This statement is confusing because the scenario being described involves a total of 12 wells, not four wells. If fracturing of multiple wells occurs simultaneously, then the duration of fracturing impacts would be less, but the combined noise level would be higher. For example, fracturing two wells at once would create a combined noise level 3 dBA higher than the fracturing of one well. When drilling and fracturing are occurring at the same time, the total noise level would be entirely driven by the much louder fracturing process (no increase in the total sound level because the difference between the two sound levels is greater than 10 dBA).

At a minimum, NYSDEC should analyze the noise impact from the same multi-pad well development scenario as used in the analysis of transportation impacts. NYSDEC should address the expected number of wells per multi-well site, the timing of drilling and fracturing at each well and the reasonable worst case noise levels that could result from the various combinations of drilling and fracturing at multiple wells on the same site.

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[2] Refer to Susan Christopherson's socioeconomics technical memorandum for more information on impacts to the tourism industry.

[3] Decibels are expressed on a logarithmic scale and thus cannot be added together directly.

2.2.2 Lack of Reasonable Noise Impact Significance Criteria

Similar to the construction impact assessment discussed in Section 2.1, the RDSGEIS presents the model results for the drilling and fracturing noise impacts without a SEQRA-compliant assessment of the significance of the results in various contexts where natural gas development is anticipated. The RDSGEIS does not include noise impact criteria against which the significance of the impacts can be assessed generically or at the site specific review level, which is contrary to the purposes of a GEIS. For information on a recommended framework for developing noise impact criteria, refer to Section 2.8.

The RDSGEIS references NYSDEC's noise policy ("Assessing and Mitigating Noise Impacts,"2001)[4], but this document has a number of significant problems that limit its usefulness in regulating noise. It discusses a 6 dBA increase as potentially significant, but does not define what averaging time period should be used in calculating the increase, does not account for increased sensitivity to noise occurring at night, and does not take into account the total level at the affected receptor. The policy also does not provide a standard for specific highly sensitive land uses, such as passive recreation parks and wilderness areas. The NYSDEC noise policy leaves too much discretion to individual analysts to ensure consistent application of noise control for an activity expected to have widespread and significant impacts across New York. Accordingly, an assessment as to the significance of the potential adverse noise impacts should be made independent of the 2001 policy.

The RDSGEIS acknowledges that drilling and fracturing would take place 24hours per day. People are much more sensitive to noise that occurs at night and interferes with sleep than to noise that occurs only during daytime activities. For this reason, community noise impact assessment metrics such as day-night sound levels (Ldn) apply a 10 dB penalty to sounds occurring at night in determining a 24-hour average energy sound level that better reflects human preferences. Background noise levels are also lower at night, further emphasizing the significance of the increase in sound levels attributable to drilling and fracturing. As noted above in the discussion of construction impacts, non-residential land uses in rural areas vital to the economic health of upstate New York such as parks, recreation areas and campgrounds would be especially sensitive to increases in sound levels.

2.2.3 Fracturing Noise Impacts Exceed Hearing Damage Thresholds

The noise levels associated with the fracturing process are of a relatively short duration on a per well basis (2-5 days), but are of an extremely large magnitude that could adversely affect human health:

- At a distance of 2,000 feet, the fracturing pump truck noise level of up to 72 dBA would be intrusive and interfere with normal conversation.
- At a distance of 500 feet, the fracturing pump truck noise level of up to 84 dBA approaches the level where hearing damage occurs (85 dBA for eight hours).

[4] http://www.dec.ny.gov/docs/permits_ej_operations_pdf/noise2000.pdf

- At a distance of 250 feet, the fracturing pump truck noise level of up to 90 dBA is in the range of noise levels where no more than 15 minutes of unprotected exposure is recommended to prevent damage to hearing.[5]
- At a distance of 50 feet, the fracturing pump truck noise level of up to 104 dBA is of a similar magnitude to a jet flyover at a distance of 1,000 feet and at a level where unprotected exposure over one minute poses a risk of permanent hearing loss.

For context in understanding the sound levels discussed above, Table 1 provides a summary of the decibel level of common sounds sources and the associated effects.

Table 1
Decibel Levels of Common Sound Sources

Sound	Noise Level (dB)	Effect
Jet Engines (near)	140	
Shotgun Firing Jet Takeoff (100-200 ft.)	130	
Rock Concerts (varies)	110–140	Threshold of pain begins around 125 dB
Oxygen Torch	121	
Discotheque/Boom Box Thunderclap (near)	120	Threshold of sensation begins around 120 dB
Stereos (over 100 watts)	110–125	
Symphony Orchestra Power Saw (chainsaw) Pneumatic Drill/Jackhammer	110	Regular exposure to sound over 100 dB of more than one minute risks permanent hearing loss.
Snowmobile	105	
Jet Flyover (1000 ft.)	103	
Electric Furnace Area Garbage Truck/Cement Mixer	100	No more than 15 minutes of unprotected exposure recommended for sounds between 90–100 dB.
Farm Tractor	98	
Newspaper Press	97	
Subway, Motorcycle (25 ft.)	88	Very annoying
Lawnmower, Food Blender Recreational Vehicles, TV	85–90 70–90	85 dB is the level at which hearing damage (8 hrs.) begins
Diesel Truck (40 mph, 50 ft.)	84	
Average City Traffic Garbage Disposal	80	Annoying; interferes with conversation; constant exposure may cause damage
Washing Machine	78	
Dishwasher	75	
Vacuum Cleaner, Hair Dryer	70	Intrusive; interferes with telephone conversation
Normal Conversation	50–65	
Quiet Office	50–60	Comfortable hearing levels are under 60 dB.
Refrigerator Humming	40	
Whisper	30	Very quiet
Broadcasting Studio	30	
Rustling Leaves	20	Just audible
Normal Breathing	10	

Source: http://www.nidcd.nih.gov/health/education/teachers/pages/common_sounds.aspx

The minimum setbacks in the proposed regulations (currently 100 feet from a residence) must be revised to protect the health and well-being of nearby residents during fracking. Landowners should not have the power to waive the minimum setback requirement. The

[5] http://www.nidcd.nih.gov/health/education/teachers/pages/common_sounds.aspx

landowners should not be presented with the temptation to trade their family's health for financial gain. An additional problem with granting landowners the ability to waive setback requirements is that tenants of a landowner's property would not have any say in the landowner's decision to waive setback requirements essential for health.

The drilling phase sound levels are substantially lower than the fracturing noise levels, but their duration is much longer (approximately one month of 24-hour drilling per well). Drilling sound levels would drop to below 70 dBA at a distance of 250 feet from the well pad. However, 70 dBA is still 40 dBA greater than the nighttime background sound level in rural areas of 30 dBA, further supporting the need for noise impact criteria and mitigation requirements to protect the soundscapes of rural areas

2.2.4 Other Comments

Tables 6.56, 6.57 and 6.58 are all incorrectly labeled as showing "estimated construction noise levels."

The equipment assumed in the analysis and sound levels associated with each piece of equipment are based on "confidential industry sources." NYSDEC should disclose the basis for the equipment assumptions and sound levels so that these important inputs can be independently validated.

Table 6.57 has footnote "2" for the rig drive motor and generator sound levels, but the explanation for footnote 2 is missing. In addition, it appears that footnote #1 on Table 6.57 should be associated with the "Distance in Feet/SPL (dBA)" portion of the table and not the sound levels associated with the top drive, draw works and triple shaker.

2.3 Transportation Noise Impacts

The RDSGEIS discusses the potential for noise impacts related to truck traffic, but fails to conduct a meaningful analysis of typical transportation noise impacts for various phases of well pad development. This failure is particularly problematic given that the detailed truck trip generation information necessary for conducting a traffic noise assessment was developed for the transportation section of the RDSGEIS.

NYSDEC should use the Federal Highway Administration's (FHWA) Traffic Noise Model (TNM) version 2.5 and the truck trip generation information to fully consider truck traffic noise impacts. While site-specific impacts cannot be assessed, NYSDEC could easily examine a hypothetical, yet realistic development scenario for one well. The analysis could look at one single public road segment from which the well site would be accessed. Receptors at various distances (50 feet to 1,000 feet) would help show the potential extent of the area where impacts could occur. A range of non-natural gas related background traffic on the modeled road could be considered to show how the increase in sound levels would be much higher for local roads with low traffic volumes than for roads with high volumes under existing conditions. Traffic noise impacts for the various receptor distances could be assessed using well established New York State Department of Transportation (NYSDOT) and FHWA criteria.[6]

[6]FHWA's noise impact assessment and mitigation procedures are defined under 23 CFR 772. NYSDOT's latest noise policy (revised April 2011) for implementing the FHWA requirements is

For the purposes of the SGEIS level of analysis, a number of simplifying, conservative assumptions could be employed in the TNM analysis (assuming flat terrain, no existing barriers, analyze one worst-case peak hour and one worst-case off-peak hour etc.). These assumptions would allow NYSDEC to complete a meaningful traffic noise analysis without extensive cost or delay to the review process.

2.4 Effects on Wildlife

Animals rely on sounds for communication, navigation, avoiding danger and finding food. Industrial and transportation noises associated with natural gas development create noise levels that can interfere with the sounds used by animals, which in turn can affect wildlife behavior and populations. The RDSGEIS acknowledges that noise could contribute to impacts on wildlife (page 6-68), but does not provide any analysis of this issue. NYSDEC should review the available scientific literature on this topic, qualitatively assess impacts and ensure appropriate mitigation measures are implemented. Key references to assist NYSDEC in this aspect of the environmental review are provided below:[7]

FHWA. Synthesis of Noise Effects on Wildlife Populations. http://www.fhwa.dot.gov/environment/noise/noise_effect_on_wildlife/effects/

Barber, J.R., K.R. Crooks, and K. Fristrup. 2010. The costs of chronic noise exposure for terrestrial organisms. Trends Ecology and Evolution 25(3): 180–189. Available at: http://www.sciencedirect.com/

Bayne, E.M., L. Habib and S. Boutin. 2008. Impacts of Chronic Anthropogenic Noise from Energy-Sector Activity on Abundance of Songbirds in the Boreal Forest. Conservation Biology 22(5) 1186-1193. Available at: http://oz.biology.ualberta.ca/faculty/stan_boutin/uploads/pdfs/Bayne%20etal%202008%20ConBio.pdf

Dooling R. J., and A. N. Popper. 2007. The effects of highway noise on birds. Report to the California. Department of Transportation, contract 43AO139. California Department of Transportation, Division of Environmental Analysis, Sacramento, California, USA. Available at: http://www.dot.ca.gov/hq/env/bio/files/caltrans_birds_10-7-2007b.pdf

Francis, C.D., C.P. Ortega and A. Cruz. 2009. Noise Pollution Changes Avian Communities and Species Interactions. Current Biology, Aug 25;19(16):1415-9 10.1016/j.cub.2009.06.052. Available at: http://www.sciencedirect.com/science/article/pii/S0960982209013281

Habib, L, E.M. Bayne and S. Boutin. 2007. Chronic industrial noise affects pairing success and age structure of ovenbirds Seiurus aurocapilla. Journal of Applied Ecology 44: 176-184. Available at: http://oz.biology.ualberta.ca/faculty/stan_boutin/ilm/uploads/pdfs/Habib%20etal%202

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available at https://www.dot.ny.gov/divisions/engineering/environmental-analysis/manuals-and-guidance/epm/repository/4_4_18Noise.pdf

[7] The suggested list of references is adapted from the USFWS paper entitled "The Effects of Noise on Wildlife." Available at: http://www.fws.gov/windenergy/docs/Noise.pdf

007%20JAE.pdf

Schaub, A, J. Ostwald and B.M. Siemers. 2008. Foraging bats avoid noise. The Journal of Experimental Biology 211: 3174-3180. Available at: http://jeb.biologists.org/cgi/content/full/211/19/3174

Swaddle, J.P. and L.C. Page. 2007. High levels of environmental noise erode pair preferences in zebra finches: implications for noise pollution. Animal Behavior 74: 363-368.

2.5 Cumulative Impacts

The RDSGEIS does not address the cumulative noise impacts of the anticipated natural gas development. Key considerations in developing a cumulative impact analysis for noise include the following:

- Analyze the cumulative noise impact of multi-well pads. The RDSGEIS analysis only addresses a single well.
- Analyze the cumulative noise impact from well site construction, drilling and fracturing in combination with the construction of pipelines and the operation of compressor stations. Pipelines and compressor stations are a reasonably foreseeable form of "induced growth" that needs to be considered.
- Examining the Ldn sound levels that would result at residences that are exposed to drilling, fracturing and truck traffic noise. The combination of these sources could result in impacts more significant than any individual source examined separately.
- Discuss regional-scale traffic noise impacts that would result from wide spread natural gas development and related economic development and temporary population growth.
- Discuss regional-scale noise impacts on human beings and wildlife, including the potential for disturbance of noise-sensitive species, such as the ovenbird (*Seiurus aurocapilla*).[8]

2.6 Mitigation

2.6.1 Mitigation for Construction Impacts

Construction noise impact mitigation is not addressed in Section 7.10 of the RDSGEIS. NYSDEC should require the use of construction noise mitigation best practices, such as those outlined in FHWA's Construction Noise Handbook. At a minimum, these measures should include:

- Requiring the use of construction noise control measures in construction contract documents. Specific noise levels can be established to ensure the protection of sensitive receptors.

[8] http://oz.biology.ualberta.ca/faculty/stan_boutin/ilm/uploads/pdfs/Habib%20etal%202007%20JAE.pdf

- Limitations on the time periods when construction could occur (e.g., prohibiting nighttime construction).
- Requiring the use of less noisy equipment and mufflers.
- Requiring temporary noise barriers when significant impacts cannot be addressed through other means.

2.6.2 Mitigation for Drilling, Fracturing and Transportation Impacts

The general types of noise mitigation measures for drilling, fracturing and trucking suggested in the RDSGEIS are reasonable, but there is no guarantee which measures, if any, will actually be required in specific circumstances. Therefore, it is likely that significant impacts will not be mitigated at the site level. In addition, the RDSGEIS states that detailed noise modeling and consideration of mitigation measures will only be required for receptors within 1,000 feet of the well pad. This requirement is illogical given the impact analysis results that show impacts extending beyond 2,000 feet. Under NYSDEC's proposed 1,000 feet distance for noise modeling, well operators could avoid assessing site specific impacts and mitigation by locating wells just beyond the 1,000 feet threshold. This could result in unmitigated significant adverse impacts for residences between 1,000 and 2,000+ feet from the well pad.

Table 2 summarizes the noise mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum or the proposed regulations. The mitigation measures not included in the EAF or regulations are not enforceable.

The proposed supplemental permit conditions (Appendix 10) state that NYSDEC can require noise mitigation "deemed necessary," but this is meaningless without a clear basis for determining when noise impacts that warrant mitigation occur. The proposed supplemental permit conditions do not contain any of the mitigation measures in Table 2 that were not addressed by the EAF or the regulations. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A), therefore it would be reasonable and consistent to also include many of the site-specific noise mitigation measures in Table 2 as supplemental permit conditions. A few of the mitigation measures in Table 2 are general enough that they should be incorporated in the proposed regulations, rather than as supplemental permit conditions. These are indicated in the "notes" column of Table 2.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate noise impacts at HVHF sites, and use this information to refine the noise mitigation requirements for future permit applications.

Table 2
Noise Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Compliance with regulatory spacing and siting restrictions. (7-128)	No	Yes (553.1)	No	
Unless otherwise required by private lease agreement, the access road must be located as far as practicable from occupied structures, places of assembly, and occupied but unleased property. (7-135)	Yes (A6-6)	Yes (560.6(a))	No	Regulation adds an additional qualifier where this provision potentially does not apply- to avoid bisecting agricultural land.
The well operator must operate the site in accordance with a noise impacts mitigation plan consistent with the SGEIS. (7-135)	Yes (A6-6)	No	No	Applies to all wells, should be in regulations
The operator's noise impacts mitigation plan shall be provided to the Department along with the permit application. (7-135)	Yes (A6-5)	No	No	Applies to all wells, should be in regulations
Additional site-specific noise mitigation measures will be added to individual permits if a well pad is located within 1,000 feet of occupied structures or places of assembly. (7-135)	Partial(A6-5)	No	No	Permit applicants are required to identify mitigation measures in the noise mitigation plan, but there is no regulatory requirement that mitigation is included in permit conditions. Applies to all wells, should be in regulations
Modifying speed limits or restricting truck traffic on certain roads. (7-130)	No	No	No	
Noise modeling for any site within 1,000 feet of a noise receptor. (7-130)	No (noise mitigation plan is required, modeling is not mentioned)	No	No	The 1,000 feet distance is arbitrary and inconsistent with the 2011 RDSGEIS analysis results which show significant impacts out to 2,000+ feet from the well pad. Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Requiring the measurement of ambient noise levels prior to beginning operations. (7-130)	No	No	No	All of the following site specific measures are required "as practicable," but no procedure or criteria for determining practicability is specified.
Potential site-specific permit condition: Specifying daytime and nighttime noise level limits as a permit condition and periodic monitoring thereof. (7-130)	No	No	No	Daytime and nighttime noise limits should be established as part of the SGEIS and regulatory process, not on a permit by permit basis that does not allow for public review. The noise limits should be consistent and included in regulations.
Potential site-specific permit condition: Placing tanks, trailers, topsoil stockpiles, or hay bales between the noise sources and receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Using noise-reduction equipment such as hospital-grade mufflers, exhaust manifolds, or other high-grade baffling. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting drill pipe cleaning ("hammering") to certain hours .(7-131)	No	No	No	
Potential site-specific permit condition: Running of casing during certain hours to minimize noise from elevator operation. (7-131)	No	No	No	
Potential site-specific permit condition: Placing air relief lines and installing baffles or mufflers on lines. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting cementing operations to certain hours (i.e., perform noisier activities, when practicable, after 7 A.M. and before 7 P.M.). (7-131)	No	No	No	
Potential site-specific permit condition: Using higher or larger-diameter stacks for flare testing operations. (7-131)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Placing redundant permanent ignition devices at the terminus of the flow line to minimize noise events of flare re-ignition. (7-131)	No	No	No	
Potential site-specific permit condition: Providing advance notification of the drilling schedule to nearby receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Placing conditions on air rotary drilling discharge pipe noise, including: -orienting high-pressure discharge pipes away from noise receptors; - having the air connection blowdown manifolded into the flow line. This would provide the air with a larger-diameter aperture at the discharge point; - having a 2-inch connection air blowdown line connected to a larger-diameter line near the discharge point or manifolded into multiple 2-inch discharges; - shrouding the discharge point by sliding open-ended pieces of larger-diameter pipe over them; or -rerouting piping so that unusually large compressed air releases (such as connection blowdown on air drilling) would be routed into the larger-diameter pit flow line to muffle the noise of any release. (7-131)	No	No	No	
Potential site-specific permit condition: using rubber hammer covers on the sledges when clearing drill pipe. (7-131)	No	No	No	
Potential site-specific permit condition: Laying down pipe during daylight hours. (7-131)	No	No	No	
Potential site-specific permit condition: Scheduling drilling operations to avoid simultaneous effects of multiple rigs on common receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting hydraulic fracturing operations to a single well at a time. (7-131)	No	No	No	
Potential site-specific permit condition: Employing electric pumps. (7-131)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Installing temporary sound barriers (see Photo 7.2, Photo 7.3, and Photo 7.4) of appropriate heights, based on noise modeling, around the edge of the drilling location between a noise generating source and any sensitive surroundings. Sound control barriers should be tested by a third-party accredited laboratory to rate Sound Transmission Coefficient (STC) values for comparison to the lower-frequency drilling noise signature. (7-131)	No	No	No	

2.7 EAF and EAF Addendum

The EAF requires land use information for a distance of one-quarter (1/4) mile around the well pad. This distance is insufficient, as many impacts (including noise and visual) extend far beyond this distance. The EAF should require the identification and mapping of land uses within one mile of the well pad, as well as additional land use mapping along local roads that would be affected by heavy truck traffic (as identified in the required transportation plan) outside the one mile area. The EAF Addendum should specifically require the identification of land uses that are especially sensitive to noise, including protected open space, recreational areas, places of worship, campgrounds, hotels, schools, and healthcare facilities.

The details of the noise mitigation plan required by the EAF Addendum are not sufficiently defined to ensure impacts are mitigated. There is a need for a standardized noise impact assessment procedure and criteria for determining the reasonableness of various levels of mitigation expenditure (e.g., the cost per benefited receptor approach used by DOTs). Without standardized requirements for assessing and mitigating noise impacts, residents in areas affected by gas development will not receive fair or consistent treatment. The NYSDEC noise guidance document does not provide sufficient detail and criteria to ensure appropriate noise analyses conducted at the site level. At a minimum, NYSDEC should provide the detailed requirements of the noise mitigation plan, addressing the following components:

- Scope of study area for the mitigation plan (recommend one-half (1/2) mile around well pad plus sensitive areas adjacent to the local roads that would experience the largest percent increase in truck traffic).
- Methodology for establishing existing noise levels (recommend requiring 24-hour measurements at a few representative receptors).
- Required protocol for assessing noise impacts: what noise metrics should be used (Ldn, Lmax, peak hour Leq, percent time audible etc.); what sources need to be considered (transportation, drilling and fracking); acceptable software modeling packages; and sources of information on appropriate sound emission levels to assume for various types of the equipment.
- Required criteria for determining which impacts are significant and require mitigation and which do not.
- Required criteria for determining how much expenditure on mitigation is reasonable to address significant adverse impacts.

One template for NYSDEC to consider adopting to specify the requirements of noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38), which is described below in Section 2.8.

2.8 Best Practice Recommendation for Noise Standards and Site-Specific Impact Assessment Protocol

The Alberta ERCB Noise Control Directive was developed through an extensive scientific review process and is recognized as one of the most stringent in the world. The Noise Control directive is based on the calculation of a permissible sound level (PSL) at

the worst case receptor in terms of equivalent energy sound level (Leq)[9] for the daytime period and the nighttime period. The PSL calculation takes into account all the important factors that influence human annoyance due to noise:

- Daytime noise is allowed to be higher than nighttime noise, reflecting the greater sensitivity to noise occurring at night.
- Existing noise levels are taken into account based on dwelling unit densities and transportation infrastructure or through ambient monitoring.
- A sliding scale of adjustment factors based on the duration of the noise accounts for the fact that people are more tolerant of a brief period of noisy activity than a noise source that continues for months or years.

As a simple example, the PSL in a low density rural area not near a major transportation corridor would be calculated as follows for the drilling of one well (35 days):

Nighttime Drilling PSL= 40 dBA basic sound level + 5 dBA adjustment due to the duration
Nighttime Drilling PSL= 45 dBA

The daytime PSL for drilling in this simple example would be 10 dBA higher, or 55 dBA.

For five days of fracking, the PSL in a low density rural area not near a major transportation corridor would be calculated as follows:

Nighttime Fracking PSL= 40 dBA basic sound level + 10 dBA adjustment due to the duration
Nighttime Fracking PSL= 50 dBA

The daytime fracking PSL would be 10 dBA higher or 60 dBA. This daytime limit would be exceeded even at a distance of 2,000 feet from the well pad based on the RDSGEIS analysis without mitigation, which estimated 72 dBA at this distance, or approximately twice as loud as the standard.

The Alberta ERCB Noise Control Directive also outlines detailed requirements to standardize the modeling of noise impacts and the preparation and documentation of noise studies that would be appropriate for NYSDEC to consider in regulating noise from HVHF in New York.

3.0 Ground-Borne Vibration and Noise

Page 6-251 of the RDSGEIS acknowledges the potential for ground-borne vibration impacts in the discussion of potential effects on property values: “Gas well development could impact local environmental resources and cause noise and vibration impacts, and trucks servicing the well development could also impact the surrounding areas.” Despite this statement, no vibration impact analysis (or an explanation of why an analysis was not conducted) is presented in the 2011 RDSGEIS. NYSDEC should analyze vibration impacts addressing the following issues:

[9] Leq refers to the constant sound level that conveys the same energy as the variable sound levels during the analysis period.

- Construction-period vibration impacts for access road and well pad development. Recommended procedures are provided in Section 12.2 of the Federal Transit Administration's *Transit Noise and Vibration Impact Assessment* guidebook. A simple qualitative assessment may be appropriate in this case. While construction activities do not typically create vibration levels capable of damaging most buildings, fragile historic buildings are more sensitive and should be avoided in the siting of access roads and well pads. Ground vibration from construction can also be an annoyance to adjacent land uses.

- Operation vibration impacts associated with drilling and fracking. This assessment should include information on drilling vibration levels from existing natural gas development in New York and other locations. While it is difficult to generalize vibration effects from one area to another due to the effects of local soils and geologic conditions, this information would provide a rational basis for identifying a screening distance for determining when a more detailed vibration impact assessment should be required at the site level. If no receptors are within the screening distance at which perceptible vibration levels could occur, then no vibration assessment would be required in the site level review.

- Operation low-frequency ground-borne noise impacts. Ground vibration can create a phenomenon known as ground-borne noise, a rumble associated with the movement of the interior surfaces of a room.[10] Special considerations apply when assessing low-frequency noise because of the non-linearity of human hearing which causes sounds dominated by low-frequency components to seem louder than broadband sounds that have the same A-weighted level. As a result, even low levels of low-frequency noise (generally defined as the frequency range below 200 Hz) can be perceived as highly annoying and contribute to sleep problems and other health problems caused by sleep disruption. In addition to sleep disturbance and physiological stress, there is strong evidence that noise exposure can contribute to cardiovascular diseases.[11] NYSDEC should assess the potential for the various phases of well development and production to generate ground-borne noise, including any on-site equipment such as condensers that have been anecdotally reported generating high vibration levels in Pennsylvania.

Based on the ground-borne noise and vibration impact assessment conclusions, the NYSDEC should identify ground-borne noise and vibration impact mitigation measures and ensure that information necessary to identify and mitigate ground-borne noise and vibration impacts at the site level is required as part of the EAF Addendum, supplemental permit conditions and/or regulations.

[10]Both ground-borne noise and vibration are issues associated with the inside of buildings and are generally not annoying outdoors.

[11] See Cardiovascular effects of noise. Noise Health. Vol. 15 Issue 52. http://www.noiseandhealth.org/showBackIssue.asp?issn=1463-1741;year=2011;volume=13;issue=52;month=May-June

4.0 Visual

4.1 Impact Assessment

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. The RDSGEIS considers and incorporates information from two studies by others that addressed the visual impact of high-volume hydraulic fracturing.[12] The public disclosure of significant adverse visual resource impacts should be improved by providing the following:

- Discussion of the various viewer groups (local residents, through travelers, tourists, etc.) that would experience changed views as a result of natural gas development and their relative sensitivity. For example, local residents are familiar with local views and may be very sensitive to changes in views they consider important. Tourists visiting an area in part to experience high visual environment quality would also be much more sensitive than general through travelers that would have passing views of natural gas development from roadways while commuting. NYSDEC should describe how natural gas development at the scale anticipated in the socioeconomic impact study would affect viewer perceptions.

- To aid in the identification and understanding of impacts, landscape similarity zones (rural open areas, rural wooded areas, villages, cities, etc.) should be identified statewide and computer modeling conducted to create three dimensional photo simulations of various phases of the well development process at various distances for each zone. NYSDEC would not need to develop this analysis from scratch—significant consultant costs could be saved by using the New York State Office For Technology's "Generic Visual Impact Assessment" prepared for the 2004 Statewide Wireless Network (SWN) DGEIS as a starting point.[13] The SWN Generic Visual Impact Assessment is an excellent example for NYSDEC to follow in comprehensively addressing visual impacts at the GEIS stage. The landscape similarity zones and representative photos selected for photo simulations used in the SWN analysis could likely be used with no to little modification. The main additional work required would be to define the components of a typical well pad development at various phases in sufficient detail and re-run the simulation model.

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[12]Upadhyay and Bu. 2010. Visual Impacts of Natural Gas Drilling in the Marcellus Shale Region. Cornell University, Dept. of City and Regional Planning: CRP 3072 Land Use, Environmental Planning, and Urban Design Workshop

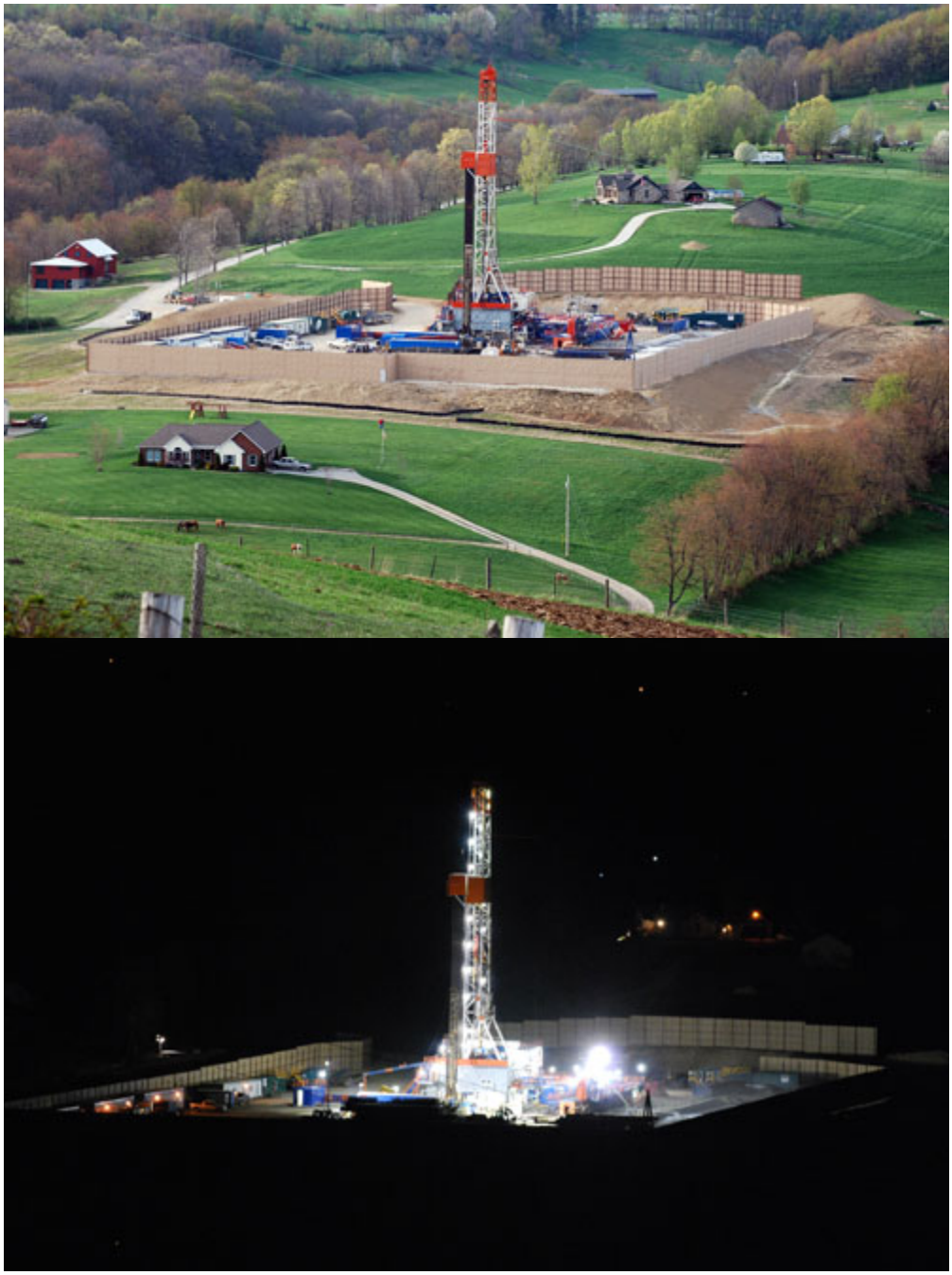
Rumbach, Andrew. 2011. Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier

[13]New York State Office for Technology. 2004. *Draft Generic Environmental Impact Statement for the New York State Statewide Wireless Network*. Cultural Resources Appendix B. Prepared by Environmental Design & Research, P.C. (now EDR Companies)

- Analysis of light pollution impacts of nighttime lighting and flaring. The RDSGEIS analysis focuses on daytime visual impacts and downplays nighttime light impacts as a "temporary impact" that most of the viewing public would not be exposed to (see page 6-281). Light pollution impacts would not be temporary when the duration of drilling, fracturing and production activities is considered for multi-well pads and cumulatively as numerous well pads are added throughout the region over the 60 year development timeframe contemplated in the RDSGEIS. The RDSGEIS ignores the visual impact to local residences that comes with the loss of pristine dark nighttime skies in rural areas. Residences are not even mentioned in the impact assessment. In many cases the nighttime impact will be more significant than the daytime visual impact because the lighting will make the well site a pronounced focal point. In addition to evaluating the visual impact of light pollution on humans, NYSDEC also needs to evaluate the impact of nighttime lighting and flaring on migratory birds.[14]

The photographs of a PA well site below illustrate the dramatic visual impact of natural gas development in a rural residential setting during the day and night.

[14] Poot, H., B. J. Ens, H. de Vries, M. A. H. Donners, M. R. Wernand, and J. M. Marquenie. 2008. Green light for nocturnally migrating birds. *Ecology and Society* **13**(2): 47. http://www.ecologyandsociety.org/vol13/iss2/art47/
For background information on light pollution impacts on wildlife see:
http://www.darksky.org/index.php?option=com_content&view=article&id=719



Day and Night Views of Chappel Unit 1H-10H in Hopewell Township, Washington County PA. Source: http://www.marcellus-shale.us/Chappel-Unit.htm

4.2 Mitigation

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present and within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not significant visual resources are present. In addition, a broader menu of more sophisticated and costly mitigation measures should be provided for those development sites that do have the potential to impact designated visual resources.

Table 3 summarizes the visual impact mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum, regulations or supplemental permit conditions. The mitigation measures not included in the EAF, regulations or permit conditions are not enforceable. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A); therefore it would be reasonable and consistent to also include many of the visual impact mitigation measures in Table 3 as supplemental permit conditions. A few of the visual impact mitigation measures that are general enough and are applicable to all well sites should be incorporated into the proposed regulations. These mitigation measures are identified in the notes column of Table 3.

Table 3
Visual Impacts Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Prepare visual impacts mitigation plan (A6-6 and Supplemental Permit Conditions).	**Yes**	No	**Yes**	Applies to all wells, should be in regulations
Flaring would only occur during initial flowback at some wells, and the potential for flaring would be limited to the extent practicable by permit conditions, such that the duration of nighttime impacts from flaring typically would not occur for longer than three days. (6-281)	No	No	No	Applies to all wells, should be in regulations
The development of measures to reduce impacts on visual resources or visually sensitive areas would follow the procedures identified in NYSDEC DEP-00-2, "Assessing and Mitigating Visual Impacts." (7-121)	No	No	No	Applies to all wells, should be in regulations
Design and siting measures, as described in NYSDEC DEP-00-2, would typically consist of screening, relocation, camouflage or disguise, maintaining low facility profiles, downsizing the scale of a project, using alternative technologies, using non-reflective materials, and controlling off-site migration of lighting (NYSDEC 2000). (7-122)	No	No	No	Design and siting mitigation measures would be primarily site specific, but some measures could be incorporated in regulations (see the mitigation measure below regarding avoiding ridgelines and minimizing light pollution).
Relocating well sites to avoid ridgelines or other areas where aboveground equipment and facilities breaks (sic) the skyline; and minimizing off-site light migration by using night lighting only when necessary and using the minimum amount of nighttime lighting necessary, directing lighting downward instead of horizontally, and using light fixtures that control light to minimize glare, light trespass (off-site light migration), and light pollution (sky glow). (7-125)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
The study also recommends the development of a best practices manual for Department staff and the industry, which would provide information on what is expected by the Department in terms of well siting and visual mitigation, and the identification of instances where visual mitigation may be necessary. (7-126)	No	No	No	
Develop a feedback mechanism in the project review process to confirm the success of measures to avoid, minimize, or mitigate visual impacts, based on the analysis of results for prior projects. (7-126)	No	No	No	
The maintenance activities described in NYSDEC DEP-00-2 should be implemented to prevent project facilities from becoming “eyesores.” Such measures would typically consist of appropriate mowing or other measures to control undesirable vegetation growth; erosion control measures to prevent migration of dust and/or water runoff from a site; measures to control the off-site migration of refuse; and measures to maintain facilities in good repair and as organized and clean as possible according to the type of project. (7-126)	No	Partial- mostly related to stormwater and erosion control	Partial- SWPPP required	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
The decommissioning activities described in NYSDEC DEP-00-2 should be implemented when the useful life of the project facilities is over; these activities would typically occur during the reclamation phase for well sites. Such activities would typically consist of, at a minimum, the removal of aboveground structures at well sites. Additional decommissioning activities that may also be required include: the total removal of all facility components at a well site (aboveground and underground) and restoration of a well site to an acceptable condition, usually with attendant vegetation and possibly including recontouring to reestablish the original topographic contours; the partial removal of facility components, such as the removal or other elimination of structures or features that produce visual impacts (such as the restoration of water impoundment sites to original conditions); and the implementation of actions to maintain an abandoned facility and site in acceptable condition to prevent the well site from developing into an eyesore, or prevent site and structural deterioration. (7-127)	Partial- site reclamation plans required, but no specific measures are required.	Partial (560.7 Reclamation)	Partial (reclamation plans required)	
The offsetting mitigation described in NYSDEC DEP-00-2 should be implemented when the impacts of well sites on visual resources or visually sensitive areas are significant and when such impacts cannot be avoided by locating the well pad in an alternate location. Per guidance in NYSDEC DEP-00-2, offsetting mitigation would consist of the correction of an existing aesthetic problem identified within the viewshed of a proposed well project. (7-128)	No	No	No	

4.3 EAF and EAF Addendum

There are a number of problems with the EAF and EAF Addendum requirements as currently drafted that will result in significant unmitigated adverse visual impacts if not corrected.

The EAF does not require sufficient information to properly identify receptors that would experience views of proposed wells. The EAF requirement is to identify the distance to the closest occupied building or outdoor facility. The EAF Addendum requires identification of "[a]ll residences, occupied structures or places of assembly within 1,320 feet." This is not a sufficient distance for assessing visual impacts and does not take into account the fact that the closest structures may not be the most impacted depending on local vegetation and topography patterns.[15] A more reasonable distance for identifying sensitive resources and receptors in most instances would be one mile.[16] The EAF addendum should require a visibility analysis to determine where the well site facilities would be visible from public roadways, parks, residences and other sensitive receptors. The number of viewers exposed and the activities viewers would typically be engaged in during exposure needs to be evaluated to determine the extent of visual impacts and the need for mitigation at the site level. NYSDEC has developed excellent guidance on this topic ("Assessing and Mitigating Visual Impacts") and a useful visual EAF addendum. These best practice approaches to visual impact assessment and mitigation should be required as part of the EAF for proposed well development sites.

Unlike the noise and traffic mitigation plans, a visual impacts mitigation plan is not a required component of the submittals to NYSDEC with the permit application, EAF and EAF Addendum. The visual impacts mitigation plan does not even have to be prepared prior to issuance of the well drilling permit and is not subject to prior approval by NYSDEC. The only apparent requirement is that the visual resource mitigation plan is prepared by the applicant in conformity with the SGEIS and made available to the NYSDEC on request. This procedure offers no opportunity for public review or even notice to affected local residents. A visual resources mitigation plan that is not subject to public review and that does not require NYSDEC approval is not an adequate mitigation measure.

[15]The RDSGEIS acknowledges that on-site equipment would be a prominent landscape feature at distances of up to double 1,320 feet used in the EAF Addendum. Page 6-274: "On-site equipment would be the most visible sign of fracturing activity and, when viewed from relatively short distances (i.e., from 1,000 feet to 0.5 miles) are relatively prominent landscape features."

[16] Although drilling activity during the daytime would be most prominent within ½ mile, a one mile distance is reasonable to account for areas with topography that could make well sites prominent features for more distant views and to address nighttime lighting impacts (which could be prominent at greater distances than the physical appearance of the well site equipment during the day.

5.0 Land Use

5.1 Impact Assessment

The RDSGEIS fails to provide any analysis of the reasonable foreseeable cumulative land use impacts that would result if high-volume hydraulic fracturing was permitted in New York. To comply with SEQRA, NYSDEC should provide the following information:

- An overview of statewide existing land uses patterns and land use planning framework. Much of this information and mapping could be adopted directly from Section 3.3.2.2 of the 2004 Statewide Wireless Network DGEIS and associated appendices. This would provide an appropriate baseline to use in assessing potential land use impacts.

- A quantitative analysis of potential land cover change at the county level. This analysis could use readily available GIS land cover data for existing conditions and assume that well development would impact land cover proportionate to the existing percentage of land cover types in each county (excluding water and developed land). Impacts could be assessed using the average 7.4 acres of disturbance per multi-well pad used in the RDSGEIS (page 5-6) and an estimate of the number of well pads by county consistent with the economic impact study county-level estimates. Cumulative impacts associated with existing trends and known major development proposals should be evaluated, taking into account the lack of capacity of rigorous land use regulation throughout most rural areas of the Southern Tier.

- A qualitative assessment of the compatibility of natural gas development with various adjacent land uses, taking into consideration impacts associated with truck traffic, noise and visual impacts. Appropriate buffer zones should be recommended between natural gas development and incompatible land uses such as residences, parks and schools to minimize impacts.

- A qualitative assessment of the consistency of natural gas development with local and regional plans. Specific land use plans and zoning regulations could not be analyzed in detail in a GEIS, but generalized planning areas common to many areas of the Marcellus shale region could be considered (e.g., rural residential, agricultural, commercial, etc.). Natural gas development should not be permitted to undermine local land use laws, especially planning in rural areas that emphasizes resource protection, open space, and scenic quality. Potential inconsistencies with plans prepared pursuant to New York's Local Waterfront Revitalization Program should be specifically considered in this assessment.

The failure of the RDSGEIS to analyze land use impacts is inconsistent with the scope for the SGEIS, which included a commitment to conduct an "[e]valuation of whether any aspect of multi-well site development or high-volume hydraulic fracturing of shale wells could be expected to change the GEIS's conclusion that major long-term changes to land use patterns, traffic and the need for public services are not anticipated as the result of gas well development. This will include review of the compatibility of shale gas development with other land uses such as agriculture, tourism, and alternative energy

development."[17] The RDSGEIS is deficient because it does not contain a land use impact assessment addressing compatibility with agriculture, tourism, and alternative energy development.

5.2 Mitigation

The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Based on the additional analyses of land use impacts recommended above, mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. The RDSGEIS should make it clear that such mitigation measures are intended to supplement any local zoning or other land use planning addressing the location of industrial uses, including gas development.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate land use impacts at HVHF sites, and use this information to refine the land use mitigation requirements for future permit applications.

5.3 EAF and EAF Addendum

The topic of consistency with local plans was not addressed in the EAF and EAF Addendum in the 2009 DSGEIS. The addition of a requirement related to the review of local plans and assessment of consistency as part of the EAF Addendum in the RDSGEIS is an improvement. The term "land use plan" should be broadly defined in the EAF Addendum to ensure it encompasses comprehensive plans, zoning ordinances, subdivision regulations, site plan review requirements, hazard mitigation plans, open space plans, agricultural/farmland protection plans, Local Waterfront Revitalization Program plans, historic districts/historic resource protection plans, economic revitalization and tourism plans, ecological and water resource protection/restoration plans etc.

With respect to the avoidance of land use compatibility impacts, the requirements of the EAF Addendum in the RDSGEIS remain extremely vague. Permit applicants are required to attest that "[u]nless otherwise required by private lease agreement, the access road will be located as far as practical from occupied structures, places of assembly and unleased property." There are no definitional or other criteria for determining what is "as far as practical" concerning location of the access road in relation to occupied structures, places of assembly and unleased property. Nor is there any required explanation by the applicant to support its affirmation or submission of a map showing such structures and uses in relation to the access road. Nor is there any required hierarchy in determining which uses of land require greatest distance from the access road in the event that movement of the access road away from one use would bring it closer to another. All that is required of the applicant is a bare affirmation that it has located the access road.

[17] NYSDEC. 2009. *Scope for the 2009 Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*. Page 41

The EAF Addendum requires the identification of "[a]ll residences, occupied structures or places of assembly within 1,320 feet." However, as noted previously, there is evidence that significant impacts (such as noise) extend beyond 1,320 feet. In order to comply with SEQRA, NYSDEC must require that the applicant identify all land uses within one mile of a proposed well. These land uses should include, but not be limited to hospitals, senior citizen residences, schools, places of worship, and residential uses.

6.0 Transportation

6.1 Impact Assessment

Additional analysis is provided in the RDSGEIS regarding truck trip generation (e.g., the number of truck trips to and from the well site at varies stages), but the impact on roadway congestion and safety has not been adequately addressed. The impacts of a typical multi-well development on congestion and safety should be analyzed in detail, as well as a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related industries. Finally, the statewide impact on vehicle miles traveled (VMT) should be reported, taking into account the long distance truck trips that would be required to haul produced water and brine waste out of state for disposal.

6.1.1 Traffic Congestion and Safety Impacts of a Typical Multi-Well Pad

The detailed analysis of the traffic congestion and safety impacts of one typical multi-well pad development serves an important purpose in terms of disclosing the general types of impacts that could occur in many similar locations, but also in terms of creating an analysis template for permit applicants to follow in developing their transportation plans for specific development proposals. A hypothetical well site could be identified in the area where the greatest drilling is expected (Region A) or an actual well site in an area of Pennsylvania representative of similar areas in New York could be analyzed. Once the hypothetical or actual well site is located, the following tasks should be undertaken:

- Identification of the project area where transportation impacts would be most likely based on actual or hypothetical information on trip origins and routes for workers, equipment and water deliveries to the site.
- Characterization of existing conditions in the project area using NYSDOT traffic counts, local data and additional traffic counts as needed. Topics to be addressed should include traffic volumes, intersection level of service, crash rates, etc.
- Analysis of impacts on traffic volumes, intersection congestion and safety consistent with the 2010 Highway Capacity Manual, NYSDOT procedures for traffic impact assessment and good transportation engineering practice.
- Development of mitigation measures to address significant impacts, such as changes in signal timing, temporary traffic signals, limitations on the routes used by water trucks, etc.

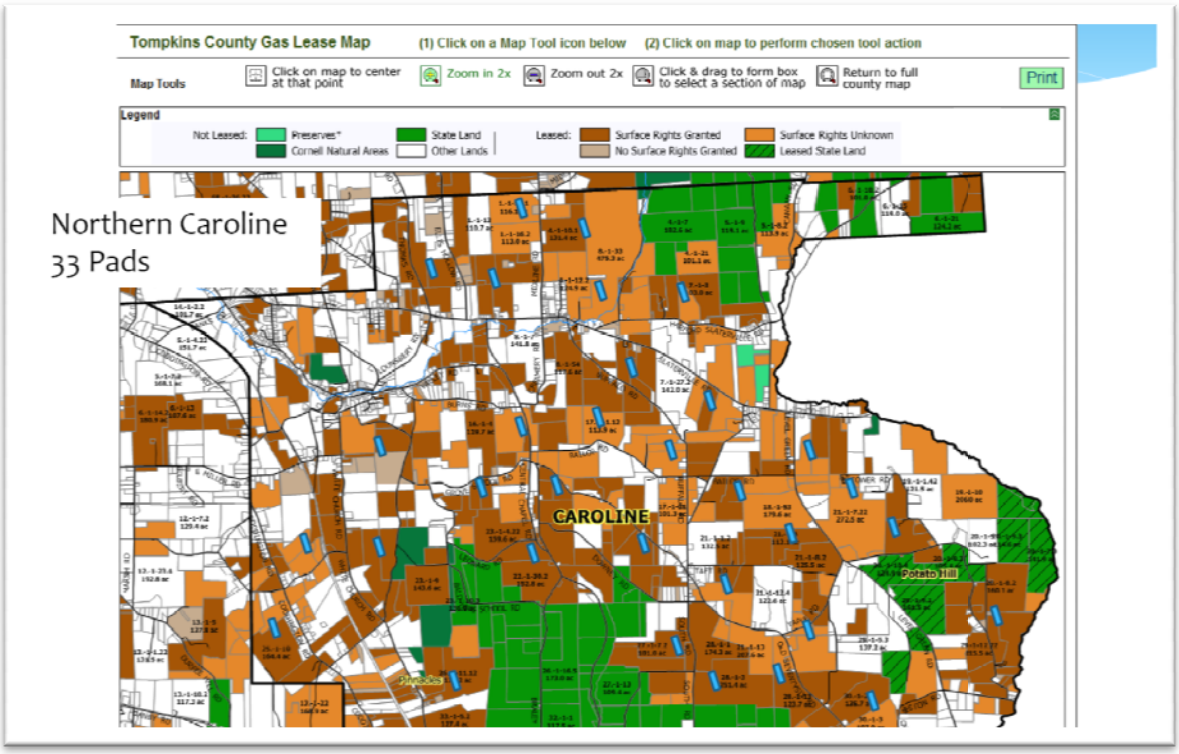
6.1.2 Regional Traffic Congestion and Safety Impacts

In addition to analyzing one well site in detail, it is important for NYSDEC to analyze regional cumulative impacts because these types of impacts will not likely be considered at the site level in the review of individual permits. The regional analysis would consider changes in traffic volumes on major roadways and the resulting potential for increased congestion and crashes from the combined effects of truck traffic to individual wells, as well as traffic related to additional employment and population growth. One methodology for conducting a meaningful regional analysis would be to use an existing travel demand model within the Marcellus and Utica shale regions. Unfortunately, neither New York State nor the Metropolitan Planning Organizations (MPOs) in Region A have a statewide or regional travel demand model. However, there are still several possible options for NYSDEC to conduct a meaningful regional scale transportation modeling analysis.

One option would be to use an analysis of Tompkins County as a surrogate for similar regional scale impacts that could occur in other places. There are several advantages to this approach:

- The Ithaca-Tompkins County Transportation Council (ITCTC) has an existing travel demand model that covers all of Tompkins County.

- The Tompkins County Council of Governments Task Force on Gas Drilling has identified realistic scenario of potential well locations for Tompkins County based on a GIS analysis and information from the 2009 DSGEIS.[18] An example map output from this analysis is provided in the figure below.



[18] http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Mapping.html

Example of Well Pad Placement Assessment for the northern portion of the Town of Caroline, Tompkins County. Source: http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Mapping%20Minutes/Section%203%20-%20TC%20Mapping%20Analysis.pdf

The travel demand model could be run for multiple scenarios but, at a minimum, future no action and action (peak year of traffic generation) scenarios should be run. Key considerations in setting up the model should include identifying the traffic analysis zones that would experience increased population and employment and appropriately defining the trips attracted to well sites and other important destinations, such as hypothetical water source areas and waste disposal areas. These parameters could easily be established by a team composed of a travel demand modeling expert and a person familiar with hydraulic fracturing well site development stages and trucking needs (making the assumptions available for public review). A cooperative study in partnership with the ITCTC could be particularly beneficial to take advantage of their familiarity with local conditions and the existing model.

Once the model runs are complete, the results should be post-processed and used to develop an informative impact analysis and mapping (e.g., link volume change maps, volume/capacity ratio maps, etc.). This type of regional analysis is routinely conducted by MPOs as part of the long-range transportation planning process. There are numerous examples and guidance sources available to NYSDEC on how to conduct regional transportation analyses for planning that are equally applicable to generic regional traffic impact analysis.[19]

6.1.3 Statewide Vehicle Miles Traveled Impact

Vehicle miles traveled (VMT) is a key indicator used in transportation planning to compare various future scenarios and investment decisions. Increases in heavy truck VMT provide a basis for drawing general conclusions about the effects of HVHF on the transportation system, as well as effects on air pollutant emissions from mobile sources. While information on the number of trips is discussed in the transportation impacts section of the RDSGEIS, VMT impacts are not addressed. The failure of the transportation section to address VMT impacts is especially problematic because statewide VMT estimates were developed for the air quality analyses in the RDSGEIS (see page 6-176). As discussed in further detail below, the RDSGEIS VMT estimates for air quality should be revised to take into account out-of-state waste disposal and incorporated into the transportation impact assessment section, as well as the air quality section.

As discussed in Glenn Miller's accompanying technical memorandum, the waste disposal requirements for produced water and brines cannot be met at any existing disposal facilities in New York. This means that a significant number of long-distance heavy truck trips would be needed to move wastes out of state for disposal. VMT information for the RDSGEIS air quality analyses was generated using average truck trip

[19]See: NCHRP Report 546: Incorporating Safety into Long-Range Transportation Planning.

FHWA. 2003. "Tools for Assessing Safety Impacts of Long-Range Transportation Plans in Urban Areas."

length information provided by the industry.[20] The industry data was from Bradford County, PA. The data collection methodology and the number of well sites upon which the industry average truck trip length estimates were developed were not disclosed in the RDSGEIS or the industry memo providing the estimates to NYSDEC. Industry estimated 100 truck trips for produced water disposal from each horizontal well, with each waste disposal truck traveling an average distance of 24 miles (one-way).[21] While supporting calculations are not provided to ascertain how the distance of 24 miles was computed, it would appear that the industry's data set was weighted heavily towards well sites where produced brine was reused at other nearby wells. This does not take into account the final disposal transportation impacts. A review of Pennsylvania Department of Environmental Protection (PADEP) waste reports[22] for Bradford County show two primary final disposal sites for brines from wells in the county:

- Pennsylvania Brine and Treatment, Inc. in Franklin, PA (approximately 200 miles from Bradford County municipalities such as Troy).
- Waste-Treatment Corporation in Warren, PA (approximately 140 miles from Bradford County municipalities such as Troy).

The 24-mile trip average distance for waste disposal provided by industry does not reflect the long distance waste hauling that occurs in Bradford County and would be expected to occur in New York. To correct this deficiency, NYSDEC should independently reevaluate the average trip length information provided by industry and develop revised truck trip length estimates that take into account final waste disposal transportation impacts. The assumptions used in generating the average truck trip length estimates should be disclosed for public review. This will allow for a more realistic assessment of the potential transportation and air quality impacts that will result from the statewide increase in VMT.

6.2 Mitigation

The majority of the transportation mitigation discussion in the RDSGEIS is focused on damage to roadways and road use agreements. While this remains an important issue, the RDSGEIS does not give sufficient attention to traffic impact mitigation measures. A list of generic mitigation measures for traffic impacts is provided (Section 7.11.3), but it is not clear when specific mitigation measures would be required because no impact criteria have been defined. For example, at what level of predicted intersection level of service would mitigation have to be considered? NYSDEC should make clear what traffic impact criteria would trigger the need for mitigation measures and include a process for local government and public review of the transportation plans for proposed well sites before NYSDEC issues a permit.

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[20] March 16, 2011 Letter from ALL Consulting to IOGA New York, obtained through a FOIL request. The footnote referencing this letter (footnote #100) was missing from the RDSGEIS.

[21] See Exhibit 19A in the March 16, 2011 ALL Consulting letter

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[22] Pennsylvania Oil and Gas Well Statewide Waste Report by Reporting Period. Jan - Jun 2011 (Marcellus Only, 6 months)
https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx

Table 4 summarizes the transportation mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum, regulations or supplemental permit conditions. The mitigation measures not included in the EAF, regulations or permit conditions are not enforceable. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A); therefore it would be reasonable and consistent to also include many of the transportation mitigation measures in Table 4 as supplemental permit conditions. Other mitigation measures are general enough to apply to all well sites and should be incorporated into regulations as described in the "notes" column of Table 4.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate transportation impacts of HVHF, and use this information to refine the transportation mitigation requirements for future permit applications.

Table 4
Transportation Impacts Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Development of Transportation Plans, Baseline Surveys, and Traffic Studies. (7-136)	Yes	Yes (560.3)	Yes- transportation plan must be approved by NYSDEC and is "incorporated by reference" into the permit	The details of the transportation plan related-requirements should be described in greater detail in the EAF Addendum, along with an example transportation plan to provide clear guidance to industry on the level of data collection and analysis NYSDEC and NYSDOT expect.
Municipal Control over Local Road Systems. (7-137)	N/A	N/A	N/A	This is a mitigation measure that cannot be implemented by NYSDEC- it relies on municipalities with very limited planning resources to be proactive in protecting their roads.
The owner or operator should attempt to obtain a road use agreement with the appropriate local municipality; if such an agreement cannot be reached, the reason(s) for not obtaining one must be documented in the Transportation Plan. The owner or operator would also have to demonstrate that, despite the absence of such agreement, the traffic associated with the activity can be conducted safely and that the owner or operator would reduce the impacts from truck traffic on local road systems to the maximum extent feasible. (7-138)	Partial- copy of road use plan must be submitted if there is one.	No	Partial- copy of road use plan must be submitted if there is one.	Applies to all wells, should be in regulations
Route selection to maximize efficient driving and public safety, pursuant to city or town laws or ordinances as may have been enacted under Vehicle and Traffic Law §1640(a)(10). (7-138)	No	No	No	Applies to all wells, should be in regulations
Avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods, as established by Vehicle and Traffic Law §1640(a)(20). (7-139)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Coordination with local emergency management agencies and highway departments. (7-139)	No	No	No	Applies to all wells, should be in regulations
Upgrades and improvements to roads that will be traveled frequently for water transport to and from many different well sites, as may be reimbursable pursuant to ECL §23-0303(3). (7-139)	No	No	No	Refers to provision of ECL that allows municipalities to request from NYSDEC "funds from the oil and gas fund to reimburse the municipality for costs incurred in repairing damages to municipal land or property. Such requests shall include such explanatory material and documentation as the commissioner may require."
Advance public notice of any necessary detours or road/lane closures. (7-139)	No	No	No	Applies to all wells, should be in regulations
Adequate off-road parking and delivery areas at the site to avoid lane/road blockage.(7-139)	No	No	No	Provision of large parking and delivery areas may increase the footprint of the well development sites, increasing ecological and water quality impacts.
Use of rail or temporary pipelines where feasible to move water to and from well sites. (7-139)	No	No	No	
Prior to site disturbance, the operator shall submit to the Department and provide a copy to the NYSDOT of any road use agreement between the operator and local municipality. (7-139)	Yes	No	Yes	Applies to all wells, should be in regulations
The operator shall file a transportation plan, which shall be incorporated by reference into the permit; the plan will be developed by a NYS-licensed Professional Engineer in consultation with the Department and will verify the existing condition and adequacy of roads, culverts, and bridges to be used locally. (7-139)	Yes	Yes	Yes	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Mitigating Incremental Damage to the State System of Roads. (7-141)	N/A	N/A	N/A	Damage to the state road system is identified in the RDSGEIS as an unmitigated impact. The Final SGEIS and HVHF regulations should include a transportation fee on permit applications to compensate for the costs of repairing HVHF-related damage to the state road system.
Limiting truck weight, axle loading, and weight during seasons when roads are most sensitive to damage from trucking (e.g., during periods of frost heaving and high runoff). (7-141)	No	No	No	
Requiring the operator to pay for the addition of traffic control devices or trained traffic control agents at peak times at identified problem intersections or road segments. (7-141)	No	No	No	
Providing industry-specific training to first responders to prepare for potential accidents. (7-141)	No	No	No	
Road use agreements limiting heavy truck traffic to off-hour periods, to the extent feasible, to minimize congestion. (7-141)	No	No	No	
Providing a safety and operational review of the proposed routes, which may include commitments to providing changes to geometry, signage, and signaling to mitigate safety risks or operational delays. (7-141)	No	No	No	
Avoiding hours and routes used by school buses. (7-141)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
1.0 Where appropriate the Department would impose specific construction windows within well construction permits in order to ensure that drilling activity and its cumulative adverse socioeconomic effects are not unduly concentrated in a specific geographic area. Those 2.0 measures, designed to mitigate socioeconomic impacts and impacts on community character, can also be employed to minimize operational and safety impacts where such impacts are identified. (7-142)	No	No	No	The effectiveness of this measure is difficult to assess because the RDSGEIS does not explain what criteria would trigger a limitation on well permits within a specific area. Applying an adaptive management approach is logical, but it requires substantial resources and planning to monitor well development pressures at the local level. NYSDEC has not explained how such a monitoring system would be implemented, and thus this mitigation measure is likely to be ignored or forgotten once NYSDEC starts issuing permits.
Reducing trucking through different technology, such as on-site treatment. (7-142)	No	No	No	
The operator will provide specific information on the types and quantities of hazardous materials expected to be transported through the jurisdictions that they will be operating in and brought on site as part of the permitting process. (7-142)	Yes	Yes (560.3)	Yes	
All fracturing fluids and additives are transported in "DOT-approved" trucks or containers. (7-142)	N/A	N/A	N/A	This measure cannot be enforced by NYSDEC- depending on federal or NYSDOT oversight of hazardous material movement.
First responders and emergency personnel would need to be aware of hazardous materials being transported in their jurisdiction and also be properly trained in case of an emergency involving these materials. Permit conditions may require the operator to provide first responder emergency response training specific to the hazardous materials to be used in the drilling process if a review of existing resources indicates such a need. (7-143)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Transportation plans may provide that sensitive locations be avoided for trucks carrying hazardous materials. (7-143)	No	No	No	To make this mitigation measure meaningful, it would be helpful for NYSDEC to identify the specific categories of sensitive facilities that permit applicants must identify and avoid in developing trucking routes (bridges over drinking water supply reservoirs for example).

6.3 EAF and EAF Addendum

A transportation plan is a required component of the EAF Addendum. The scope of the transportation plan is discussed in RDSGEIS Section 7.11.1.1 and includes "the number of anticipated truck trips to be generated by the proposed activity; the times of day when trucks are proposed to be operating; the proposed routes for such truck trips; the locations of, and access to and from, appropriate parking/staging areas; and the ability of the roadways located on such routes to accommodate such truck traffic." NYSDEC should provide details on the scope of the specific analyses that should be performed for the transportation plan to ensure a uniform approach is used.

7.0 Community Character

7.1 Impact Assessment

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources, historic resources, socioeconomics, traffic, and noise (CEQR Tech. Manual). The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how proposed new natural gas development in the Marcellus and Utica shales would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each).

The community character impact assessment in the RDSGEIS appears to be based on the *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in Marcellus Shale and Other Low-Permeability Gas Reservoirs* report prepared by NTC Consultants for NYSERDA. To the extent the analysis in the RDSGEIS derives from or relies upon this report, it is significantly flawed in that for the most part it considers a few of the elements of community character individually (visual, noise, traffic), without drawing conclusions on the cumulative impact of all the changes associated with the expected level of new development. Much of the cumulative impact discussion in the report focuses on attempting to explain why a regional cumulative impact assessment based on a reasonable worst case development scenario is not necessary or helpful. The report also states:

> "The approach for addressing regional cumulative impacts is to focus on the proactive siting of well pads as discussed in previous sections of this report. If the location and construction of each well pad is based on 'Best Practices' (See Appendix A) then the potential impacts will be lessened and/or eliminated. **When applications are reviewed, it is recommended that DEC examine any negative issues that have occurred on adjacent well pads to determine if there is a potential problem in the area that needs further scrutiny**." Page 38. Emphasis added.

The suggested approach is to let the impacts occur and then do something about those impacts if there is a problem. NYSDEC adopted this approach in the form of the vague mitigation commitment to monitor the pace of well development and respond through limits on permits in specific areas to minimize cumulative socioeconomic impacts (see page 7-120). This is contrary to SEQRA, the intent and spirit of which is to consider impacts *before* making a decision to approve the proposed action. NYSDEC must address regional cumulative community character impacts and not defer the issue to the future after the impacts have occurred. An adaptive management framework to addressing HVHF impacts is useful (as discussed further below), but this does not excuse the omission of a complete community character impact assessment in the RDSGEIS.

7.2 Mitigation

The community character mitigation section of the RDSGEIS focuses on the EAF Addendum requirement related to consistency with local plans. There is also a mitigation commitment requiring site-specific review and additional mitigation measures of disturbance of 2.5 acres or more within an agricultural district. However, the agricultural district mitigation commitment is not enforceable because it is not included in the EAF Addendum, regulations or supplemental permit conditions.

The community character mitigation section also references the visual, noise, transportation and socioeconomic mitigation commitments in Chapter 7. However, as noted in the other sections of this review, enforceable mitigation has not been provided for those topics, which means that the unmitigated impacts in those subject areas will contribute to unmitigated community character impacts.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate community impacts of HVHF, and use this information to refine the community impacts mitigation requirements for future permit applications. NYSDEC contemplates such a similar approach in the discussion of mitigation for socioeconomic impacts (page 7-120), but the details of how this monitoring system would work need to be defined and circulated for public review and comment.

7.3 EAF and EAF Addendum

Community character impacts are not addressed as a distinct topic in the EAF or EAF Addendum.

8.0 Cultural Resources

8.1 Impact Assessment

Cultural resources, also referred to as historic properties, link a community with its past. These are finite resources and are provided protections through local, state, and federal authorities. In the 1992 GEIS, cultural resources were addressed as one of the major environmental issues. In GEIS Chapter 6, a background of these environmental resources and a review of the then-existing authorities (in addition to SEQRA) was

provided, noting "the revised, shortened and simplified EAF should still remain as an attachment to the drilling permit application form (FGEIS page 31)." The simplified EAF includes cultural resources and offers the New York State Office of Parks, Recreation, and Historic Preservation (OPRHP, the State Historic Preservation Office) as a source for information along with the DEC Division of Construction Management-Cultural Resources Section and the DEC Division of Regulatory Affairs-Regional Office. There was limited discussion of the potential cultural resource issues beyond that identified on pages 6-16, 7-7, and 16-11 through 16-12. Further, although the 1992 GEIS highlighted the need for consultation between NYSDEC and the OPRHP, there was no formal process for consideration of cultural resources outlined.

Despite the length of time since the 1992 GEIS was issued, the 2009 DSGEIS and the RDSGEIS provide no update or reaffirmation of the authority-driven procedures for taking potential impacts to cultural resources into account beyond referring back to the 1992 GEIS. For example, how will tribal consultation be addressed given the 2009 DEC policy, *Contact, Cooperation, and Consultation with Indian Nations*:

> "'Affecting Indian Nation interests' means a proposed action or activity, whether undertaken directly by the Department or by a third party requiring a Department approval or permit, which may have a direct foreseeable, or ascertainable effect on environmental or cultural resources of significance to one or more Indian Nations, whether such resources are located on or outside of Indian Nation Territory."

In the RDSGEIS there is limited new discussion of cultural resource issues despite comments provided during the scoping process by the New York Archaeological Council (NYAC) dated December 11, 2008, outlining the potential loss of valuable scientific information should no consideration be given to these finite resources. NYAC reinforces the direct impacts to archaeological deposits that can result from any ground disturbing activity and offers comments on potential indirect impacts, such as vibration from drilling and increased vehicular traffic that could impact fragile archaeological deposits, or the potential for loss or degradation of the information that could be gleaned from specialized analyses of archaeological features that may result from changes to the soil matrix with the introduction of chemical additives as well as the potential for indirect (visual, vibration) impacts to historic architectural resources. Despite the availability of these comments, the additions to the RDSGEIS focus solely on the potential for visual impacts but disregard NYAC's other recommendations, a notable deficiency in the 1992 document.

In \RDSGEIS Chapter 3, there is no mention of cultural resources relative to SEQRA beyond the reference back to the 1992 findings. In Chapter 6, there is no discussion of cultural resources; while the 1992 document and its findings are incorporated by reference and this chapter is intended to address new issues, this is a missed opportunity to consider potential impact to cultural resources. Consider the potential situation where a cultural resource, such as the remnants of an old water-powered mill complex that once was the economic hub for a small community or what remains of an historic vessel scuttled during a military skirmish, is submerged or partially submerged in an anaerobic environment. With a reduction in stream flow there is the potential to degrade the resource, rendering it subject to deterioration and potential loss. Without consideration of a broadly defined area of potential effect at the outset when the siting application and all its associated contingencies (e.g., well pads, gathering lines,

distributions lines, access roads, resource or water needs, etc.) is reviewed, there is the potential to impact cultural resources.

The RDSGEIS does note in Chapter 8, Table 8.1, that OPRHP has a role in "well siting" and in "new in-state industrial treatment plants" but these are shown with an asterisk, with the caveat "role pertains in certain circumstances." On page 8-6, it is noted that "[i]n addition to continued review of well and access road locations in areas of potential historic and archeological significance, OPRHP will also review locations of related facilities such as surface impoundments and treatment plants." On page 8-37, the State Historic Preservation Act (SHPA) is brought into play with respect to dam safety permitting criteria and thresholds for resource consideration. And in Appendix 14 (Department of Public Service Environmental Management & Construction Standards and Practices –Pipelines), cultural resources are listed under the portion of the checklist for "Procedures for the Identification and Protection of Sensitive Resources."

Thus, the big issue that has not been adequately outlined and addressed is how cultural resources will be handled in the overall permitting process; in particular, what is the procedural means and proposed agency coordination for cultural resources identification, and impact evaluation, minimization, avoidance, mitigation?

8.2 Mitigation

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would be considered when designated significant visual resources associated with historic resources are present and within the view shed of proposed wells. However, in order to determine whether there is a view shed impact on a historic resource the resource itself must be identified, and evaluated before a determination of impact can be made. Because the RDSGEIS does not, as noted, indicate how this will be done, it is impossible to evaluate whether the process for impact identification and mitigation pursuant to SEQRA will be adequate.

The same can be said for ***all*** potential cultural resource impacts, such as those to archaeological sites which are rarely visible on the surface – mitigation measures would be considered once any resources have been identified, evaluated for significance, and a determination made that the impact cannot be avoided or minimized. It is expected that this process is to be undertaken during consideration of well siting applications (which should take into account gathering and distribution lines, access roads, all potential ground-disturbing impacts as well as potential indirect impacts [i.e., vibration, chemical, visual, etc.]). Unfortunately, this approach does not allow the public adequate review of possible mitigation efforts.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate cultural resource impacts of HVHF, and use this information to refine the cultural resource mitigation requirements for future permit applications.

8.3 EAF and EAF Addendum

As noted above, the process for addressing potential cultural resource impacts is not fully developed beyond the EAF checkboxes and DEC review of the application.

9.0 Aquatic Ecology

The assessment of aquatic ecology issues focused on the following items:

- Potential for impairment of the "best use" classifications of the State's surface waters due to cumulative impacts.
- Potential for the alteration or degradation of critical aquatic habitat for aquatic species with limited distributions and sensitivity to water quality, such as trout and salamanders (e.g., the common mudpuppy (*Necturus maculosus*).
- Potential for aquatic habitat fragmentation (i.e., the isolation of existing populations).

LBG's review of Sections 6.1.1.2, 6.1.1.3 and 6.1.1.4 of the RDSGEIS indicates that the document does not fully characterize the potential environmental impacts leading to the potential degradation of a stream's best use classification, and the alteration of aquatic habitats and ecosystems due to direct and cumulative impacts. The RDSGEIS inadequately addresses the potential for the regulated development of high-volume hydraulic fracturing to alter critical aquatic habitat for sensitive species, specifically trout and salamanders, and no provisions are made in sections 7.1 and 7.4 to require standard mitigation measures to ensure degradation is avoided.

Pursuant to NY State Environmental Conservation Law regulations, Chapter X - Division of Water, Article 2, Part 701, all fresh surface water classes have a general condition that does not allow the discharge of wastes to impair the best usage of the receiving water, and all surface water use classifications "shall be suitable for fish, shellfish, and wildlife propagation and survival." The regulations provide for further discharge restrictions to surface waters that occur within the RDSGEIS study area, including:

- Part 701.20: c.2 – waters that contain "critical aquatic habitat for fishes, amphibians, or aquatic invertebrates listed as endangered, threatened, or of special concern in Part 182 of this Title"; d.3 "small trout spawning streams;"
- Part 701.25 a. – waters that are labeled with the symbol (T) are "classified waters in that specific item are trout waters. Any water quality standard, guidance value, or thermal criterion that specifically refers to trout or trout waters applies;" and,
- Part 701.25 b. – waters that are labeled with the symbol (TS) are "classified waters in that specific Item are trout spawning waters. Any water quality standard, guidance value, or thermal criterion that specifically refers to trout, trout spawning, trout waters, or trout spawning waters applies."

The purpose of the discharge designations is to provide further protection to these waters by defining their best use as the maintenance of aquatic species diversity and populations of sensitive or diminishing species that are sensitive to the degradation of water and habitat quality. The combined land use changes caused by well pad development, roadway network improvements and expansion, and supporting

infrastructure should be described within the RDSGEIS at a watershed scale that is practical to the management of aquatic resources.

To assist in defining a potential scale, LBG prepared maps that depict the frequency, spatial distribution and arrangement of discharge restricted sensitive aquatic environments (trout streams) at two watershed scales (See Figures 1 and 2). Figure 1 shows the distribution of streams with NYSDEC discharge designations for trout within the Unadilla river watershed, a large tributary to the Susquehanna River with a 520 square mile watershed. Figure 1 shows the number of and connectivity between patches of existing stream habitat and populations of trout, and presumably other sensitive aquatic species. Figure 2 shows the Lower Butternut Creek watershed at the Hydrologic Unit Code (HUC) 12 level, with a 52.16 square mile watershed. Lower Butternut Creek is a tributary of the Unadilla River. At this scale, Figure 2 can be used as a planning level tool to depict aquatic habitat cores, islands, and corridors for a single or multiple populations of aquatic species. The scale is also practical for relating well pad and ancillary features with potential impacts and mitigation considerations. In the RDSGEIS, NYSDEC should use similar planning tools to evaluate more thoroughly potential impacts to aquatic habitat.

Table 5 below summarizes the watershed features of size, length of trout supporting (T) and trout spawning (TS) designated waters, and length of existing roads for both figures.

Table 5
Watershed Statistics

Watershed	Watershed Size (sq. miles)	Non-Trout Waters (miles)	Trout Supporting/ Trout Spawning Waters (miles)	Existing Roads (miles)
Unadilla River	520	587.63	461.85	1488
Lower Butternut Creek	52.16	88.26	49	134

Construction of well pads, access roads and supporting infrastructure may impact two major watershed processes which could have multiple cumulative effects on surface waters.

The first process is the increase in concentrated runoff from construction sites due to precipitation or snow melt through the re-routing and concentrating of diffuse overland sheet flow into roadside ditch networks, and the reduction in soil infiltration and permeability due to land development (or changes in water supply distribution) (Rosgen 2006, Forman et al. 2003, Leopold and Langbein 1960).

Second, the increase in sediment from the introduction of miles of new access roads with a gravel base, unpaved shoulders, and/or unconsolidated drainage conveyances/ditches, and stream crossings is a process that can lead to changes in sediment supply. Gravel roads, even when properly constructed and maintained, provide a source of sediment, especially during high traffic periods (Rosgen 2006, Forman et al. 2003, Reid and Dunne 1984). Each of these items is discussed below.

9.1.1 Land Use

Sections 5.1.1, 5.1.2 and 5.1.3 of the RDSGEIS describe the extent of land disturbance during the drilling and fracturing stage for a well pad and ancillary features (access

roads, utility corridors, compressor stations, etc.). The average total disturbance was estimated at 7.4 acres for a multi-well pad and 4.6 acres for a single well pad.

Section 5.1.4.2 of the RDSGEIS states that the spacing of disturbances from horizontal wells with multiple wells drilled from common pads is "up to 640 acres," which is approximately one well pad per square mile. An "on average" spacing estimate is not provided; therefore, a typical disturbance footprint spacing has not been quantified. Analyses of cumulative impacts at a watershed scale require a practical spacing or range of spacing to better evaluate the need for regulatory limitations on well pad densities. If truly representative of the affected acreage, a single 7.4 acre multi-well pad represents approximately 1.5 percent of the area within a square mile.

A common component of construction is the clearing, grading and compaction of land within the disturbance footprint. These actions impact the naturally occurring drainage patterns outside of the disturbance footprint by re-routing and concentrating diffuse overland sheet flow produced by precipitation or snow melt (Leopold and Langbien, 1960; Leopold, 1994), re-directing this water through surface conveyances such as a ditch network (Foreman et al. 2003), which can change the timing and path of water supplied to surface waters within the watershed (Rosgen, 2006) or the hydrologic regime (Poff et al., 1997). The RDSGEIS does not specifically address these processes or address potential mitigation measures for inclusion as permit conditions within the regulatory program.

In reference to partial reclamation of the well pad, Section 5.16.1 states that "[s]ubsequent to drilling and fracturing operations, associated equipment is removed. Any pits used for those operations must be reclaimed and the site must be re-graded and seeded to the extent feasible to match it to the adjacent terrain. Department inspectors visit the site to confirm full restoration of areas not needed for production."
The intention of partial reclamation of a pad during the production phase is to further reduce the footprint of the disturbance. However, this section does not describe details about how long each phase lasts, does not provide a reclamation time table, or performance standards. Therefore, it is difficult to classify the disturbance as a temporary or permanent impact. The section provides insufficient elaboration or methods and does not define the industry standards or success criteria for reclamation activities and the environmental benefits they may provide; therefore, the value of reclamation as mitigation is also unclear.

Land use restrictions using impervious area thresholds are used to maintain brown trout populations in suburban watersheds in Delaware, Maryland and Pennsylvania (Kauffman and Brant, 2000) which is based on limiting impervious surfaces to less than 10% coverage of a watershed. Brook trout populations, the very species associated with T and TS stream designations in NY have become extirpated in watersheds with impervious land uses above 4% coverage, and stress upon brook trout populations was inversely related to impervious watershed coverage (Stranko et al., 2008). Brook trout population presence is shown to have a positive relationship with forested watershed coverage above 68% (Hudy et al. 2008). Collectively, this information demonstrates that cumulative watershed land use changes induced by HVHF that impact forested land and increase impervious cover is likely to cumulatively impact NY State designated trout and trout spawning waters which could well lead to the loss of the waters' best use designations. NYSDEC should address these issues in the RDSGEIS. In addition, related impacts to tourism are not discussed here but should be as these impacts are an

indirect effect of natural habitat degradation and natural habitat is an established State tourism asset.

9.1.2 Access Roads

Section 5.1.1 of the RDSGEIS states “industry estimates an average access road size of 0.27 acre, which would imply an average length of about 400 feet for a 30-foot wide road. Permit applications for horizontal Marcellus wells received by the Department prior to publication of the 2009 DSGEIS indicated road lengths ranging from 130 feet to approximately 3,000 feet.” The Executive Summary, Chapter 2 summary of the RDSGEIS states “the Department has determined, based on industry projections, that it may receive applications to drill approximately 1,700 - 2,500 horizontal and vertical wells for development of the Marcellus Shale by high-volume hydraulic fracturing during a ‘peak development’ year. An average year may see 1,600 or more applications. Development of the Marcellus Shale in New York may occur over a 30-year period. Those peak and average levels of development are the assumptions upon which the analyses contained in this RDSGEIS are based.” Based only on the averages considered in the RDSGEIS, an average of 1,600 wells annually, each requiring 400 feet of new road, according to the RDSGEIS would result in over 121 miles of new, likely gravel, roads annually. This would be over 3,600 miles of new roads over 30 years. The RDSGEIS does not address the potential impact of the additional roads on aquatic resources, especially streams with sensitive species.

Stream drainage density relative to road density across a watershed is indicative of the interconnectivity of the roadway drainage system with the stream ecosystem (Foreman et al. 2003). In a regional study of the distribution of brook trout in their native range, average road densities of 3.2 km/sq. km was shown to be a predictor of watersheds that are not likely to support intact brook trout habitat (Hudy et al. 2008). Road density within the lower Butternut Creek watershed is 2.57 miles/sq. mile and the stream density is 2.63 miles/sq. mile. Within the lower Butternut Creek watershed, the stream network is less likely to be designated as Trout or Trout Spawning in areas where roads cross the stream more frequently. For instance, the stream network is designated as Trout or Trout Spawning stream segments are crossed by roads 38 times, and non-trout where stream segments are crossed by roads 54 times or more (Figure 2). While other land use factors can be at play here, road density within a watershed is positively correlated with stream habitat condition. The RDSGEIS should exam available literature on this topic to aid in the assessment of potential long term impacts to trout populations within affected watersheds due to watershed level changes. It is likely that some watersheds currently supporting trout populations are at or near the tipping point of trout sustainability. The RSDGEIS does not address how future HVHF development may affect native trout populations and other sensitive aquatic species.

Road crossings have been identified as a source of habitat fragmentation within linear aquatic systems by forming barriers to fish passage and altering the continuity of fluvial processes (e.g. sediment transport and disconnecting a stream from its floodplain) (Foreman, 2003). Road crossing structures can also change the transport of Large Woody Debris (LWD) (Foreman et al. 2003). LWD is important as an indicator of trout habitat quality (Flebbe and Dolloff, 1995) and in routing, storing and sorting sediment in fluvial landforms (Fisher et al. 2010, Lassettre and Harris 2001, Gomi et al. 2001 and Montgomery et al. 1995).

The alteration of fluvial processes caused by watershed development includes increased peak flows and mobilization of sediment from watershed and stream channel sources (Leopold 1994). Gravel roads, particularly construction and repair of gravel roads, have been shown to be a source of sediment in watersheds (Rosgen 2006) and contribute to habitat degradation (Logan, 2003). Heavy vehicle traffic on gravel roads, up to four heavy vehicles per day, has been shown to contribute up to 130 times more sediment to streams than paved roads (Reid and Dunne, 1984). The drilling and fracturing process can require tens to hundreds of trips by heavy vehicles each time a new well is constructed, thus increasing the likelihood of new sediment loadings to the local stream. Currently New York State provides no regulatory guidance for stream crossing design which maintains Aquatic Organism Passage (AOP). Vermont Department of Environmental Conservation, Watershed Management Program has developed stream crossing design guidance and stream crossing assessment tools which support AOP and natural channel morphology (The Vermont Culvert Geomorphic Compatibility Screening Tool, 2008 and The Vermont Culvert Aquatic Organism Passage Screening Tool, 2009). These tools can be used to design habitat sensitive crossings at new roads and find mitigation through retrofit or replacement of existing non-habitat sensitive crossings. The Massachusetts Department of Environmental Protection has developed guidance for maintaining gravel roads, ditch networks and stabilizing cut slopes to prevent erosions and reduce sediment inputs to the watershed (The Massachusetts Unpaved Roads BMP Manual, 2001). The adoption or incorporation of these practices as standard BMP measures within the regulatory program should be addressed within the RDSGEIS as a means to minimize potential impacts.

Section 6.4.3 of the RDSGEIS provides an incomplete characterization of potential environmental impacts to endangered and threatened species. While Chapter X, Part 701.20: c.2 states “critical aquatic habitat for fishes, amphibians, or aquatic invertebrates listed as endangered, threatened, or of special concern in Part 182 of this Title” includes discharge designations for waters with species of special concern, the RDSGEIS does not adequately recognize critical habitats for aquatic species of special concern, nor does it provide a complete list of species of special concern that are dependent on aquatic habitats as part of their natural life cycle. There is insufficient evaluation of species of special concern and potential cumulative impacts to threatened, endangered or special concern species within the RDSGEIS.

9.1.3 Recommendations

Based on the review of the RDSGEIS, LBG has found that the document does not adequately address the potential direct and cumulative impacts of HVHF on aquatic resources, New York State designated trout and trout spawning waters, and the potential for the loss of the waters’ best use designations. Recommendations to address the deficiencies of the RDSGEIS are provided below.

1. The RDSGEIS should provide a technically supported evaluation method to assess the anticipated changes to land use and road networks at a watershed level and the potential impact to aquatic habitat and sensitive aquatic species.

2. The RDSGEIS should define the restoration standards and success criteria for well pads, access roads and other short term and long term disturbances,

and timelines so that the temporal impacts of these activities and the environmental benefits of site reclamation are clearly defined.

3. Currently New York State does not provide regulatory guidance for stream crossing design which maintains Aquatic Organism Passage (AOP).The adoption or incorporation of these practices as standard BMP measures within the regulatory program should be addressed within the RDSGEIS as a means to minimize potential impacts.

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Onondaga

Oneida

Madison

Herkimer

Fulton

Montgomery

Otsego

Cortland

Chenango

Schoharie

Delaware

Lower Butternut Creek Sub-Watershed

Legend

- NY County Boundaries
- Extent of Marcellus Shale
- Extent of Utica Shale
- Unadilla River Watershed Boundary
- Streams
- Trout Streams
- Trout Spawning Streams
- Main Roads
- Secondary Roads

0 2.5 5 10 Miles

Source:
Roads - NYS Roads - New York State Office of Cyber Security, 2011
Watersheds - 12 Digit Watershed Boundary - U.S. Geological Survey New York Water Science Center and U.S Department of Agriculture, New York State Natural Resources Conservation Service, 2009
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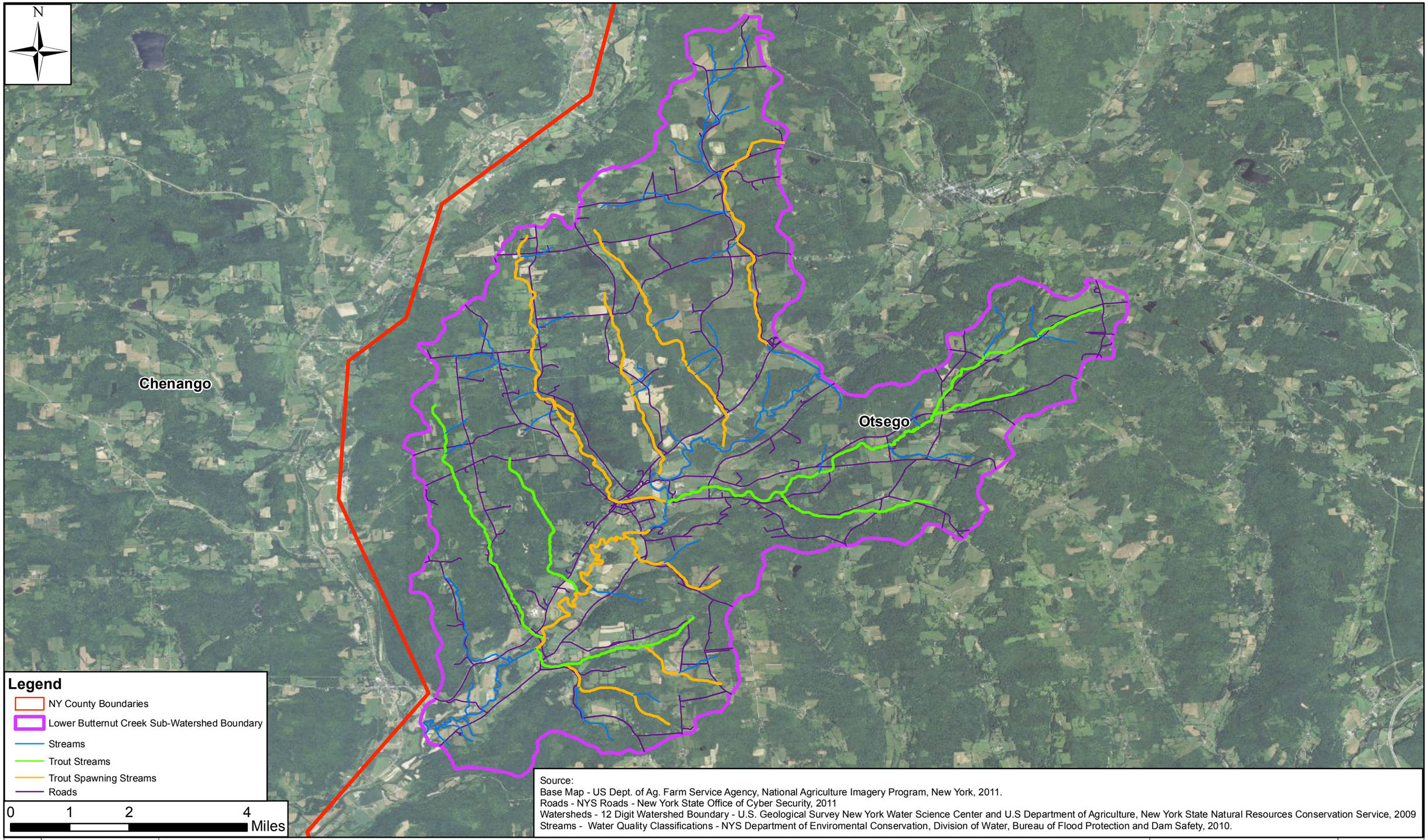
Natural Resources Defense Council

UNADILLA RIVER WATERSHED MAP

NEW YORK

The Louis Berger Group, Inc.
412 Mt. Kemble Ave
Morristown, NJ

FIGURE 1



Source:
Base Map - US Dept. of Ag. Farm Service Agency, National Agriculture Imagery Program, New York, 2011.
Roads - NYS Roads - New York State Office of Cyber Security, 2011
Watersheds - 12 Digit Watershed Boundary - U.S. Geological Survey New York Water Science Center and U.S Department of Agriculture, New York State Natural Resources Conservation Service, 2009
Streams - Water Quality Classifications - NYS Department of Enviromental Conservation, Division of Water, Bureau of Flood Protection and Dam Safety, 2010.

Natural Resources Defense Council

LOWER BUTTERNUT CREEK SUB-WATERSHED MAP

NEW YORK

The Louis Berger Group, Inc.
412 Mt. Kemble Ave
Morristown, NJ

FIGURE 2

Attachment 8

Kevin Heatley, M.EPC LEED AP

Professional Review & Comment

on

Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (Revised September 7, 2011)

January 5, 2012

Prepared for:

Delaware Riverkeeper Network

Prepared By:

Kevin Heatley, M.EPC LEED AP

Restoration Ecologist

EXECUTIVE SUMMARY

This review of the New York State Department of Environmental Conservation (NYDEC) revised draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program (issued September 7, 2011) was prepared in response to a request by the Delaware Riverkeeper Network to provide expert opinion on issues of terrestrial and restoration ecology. The ecological health and integrity of the forested landscapes located within watersheds has a direct bearing on both the water quality and the biotic composition of the streams and aquatic resources of the Delaware River and other major drainages of the Marcellus and Utica region. Mitigation of land disturbance impacts, such as those associated with unconventional fossil fuel extraction, is critical to ecological sustainability.

The NYDEC recognizes in section 1.2 of the RDSGEIS that it is required by NY state law to "conserve, improve and protect its natural resources and environment . . ." However, the agency openly, and correctly, acknowledges that this mandate cannot be achieved for terrestrial habitats and wildlife resources in the state under the proposed RDSGEIS mitigation recommendations. According to section 7.4.1, "Significant adverse impacts to habitats, wildlife, and biodiversity from site disturbance associated with high-volume hydraulic fracturing in the area underlain by the Marcellus Shale in New York will be unavoidable." The agency presents no mitigation option, such as aggressive region-wide restrictions on the spatial and/or temporal scale of this land disturbance sufficient to negate the undesirable ecological impacts of shale gas development.

The RDSGEIS identified four major areas of concern with respect to ecosystems and wildlife:

1. Fragmentation of habitat
2. Potential transfer of invasive species
3. Potential impacts on endangered and threatened species
4. Use of certain state-owned lands

While the RDSGEIS correctly emphasizes the importance of habitat fragmentation on terrestrial vertebrate species (in particular avian organisms) it fails to document the long term ecological consequences of fragmentation, deforestation, increasing forest edge and reduced surface permeability on desirable forest regeneration, surface water quality, soil chemistry, biodiversity, and sustainable ecosystem services.

Unfortunately, the mitigation measures proposed fail to fully address fragmentation and landscape connectivity issues for the majority of the affected ecosystems. In addition, the proposed invasive species best management practices lack the following key components:

- Quantifiable control metrics
- Latent seed bank management
- Forest edge management

The RDSGEIS also fails to provide any effective regulatory guidance and/or mandates regarding the final ecological restoration of ecosystem structure and function to well pads, pipelines, access road sites, and other related infrastructure upon cessation of natural gas extraction activities.

As written, the revised draft RDSGEIS presented by the NYDEC assures that widespread, dramatic changes in both the current integrity, and the future successional trajectory, of the watersheds and forests in the Marcellus and Utica regions will occur should the anticipated level of landscape industrialization occur. Changes in the successional trajectory (the type of tree species regenerating in the forest understory and that will ultimately comprise the forest canopy) will cause cascading ecological consequences. These changes are likely to result in an undesirable diminution of the ecosystem benefits and services currently provided by these biotic communities. Cascading ecological effects and consequences are probable and will require costly management interventions of significant spatial and temporal scale in order to achieve system restoration.

DISCUSSION

A careful review and analysis of the draft NYDEC RDSGEIS reveals a number of areas of concern with respect to the maintenance of the ecological integrity of terrestrial ecosystems and the corresponding impacts upon aquatic resources. In particular the RDSGEIS does not adequately provide for the protection and sustainable regeneration of critical headwater forests within the Delaware River drainage. Forested ecosystems are the dominant land cover type (57%) within the areas of potential shale gas extraction in the State of New York. This canopy cover is of extreme importance to both the quality and quantity of water that flows within the Delaware River drainage.

Forests filter contaminants, moderate stream temperatures and buffer flow volumes associated with precipitation events. They are the structural foundation upon which the ecological integrity and health of the basin's biological resources are built. The link between percent forest cover and water quality is clearly established in the scientific literature. As an example, reductions in forest cover are directly correlated with negative changes in water chemistry, such as increases in nitrogen, phosphorus, sodium, chlorides, and sulfates, and with reductions in stream macroinvertebrate diversity (Jackson and Sweeny 2010).

A healthy, viable forest canopy creates tangible economic value that accrues directly to local and regional communities. This value comes both from forest-dependent industries and from the ecosystem services (air filtration, climate regulation, water purification, etc.) that the forest provides. For instance, a 2002 survey of 27 water suppliers found that for every 10% increase in forest cover within a municipal watershed, the costs of water treatment and purification decreased by approximately 20% (Ernst, Caryn, Gullick and Nixon 2004). In New York State, forest-dependent industries are estimated to generate nine billion dollars of economic activity on an annual basis (North East State Foresters Association 2001).

Forest fragmentation as a result of anthropogenic landscape modification is well recognized within biogeographic theory and conservation biology as a leading cause of local species extinctions (extirpation). It can also cause dramatic shifts in the floral and faunal composition of woodland communities. Sub-lethal impacts to floral and faunal

populations (population isolation, reduced genetic fitness and diversity) have also been associated with disruptions to forest connectivity (Clark, et.al. 2010).

Species dependent upon large, intact areas of interior, or "core" forest and those with limited dispersal abilities are at particular risk from forest fragmentation. A large body of scientific literature associated with neotropical migratory birds clearly links the survival of many of these species to the preservation and restoration of core forest habitat. The Cerulean warbler *(Dendroica cerulean*), a species of special concern in New York State, is a prime example. These populations are already in decline due to massive reductions in the amount of intact core forest. Even if the remaining interior forest habitat is preserved, the extensive fragmentation of the rest of the forested landscape will effectively preclude these areas from reconnection and restoration as interior forest habitat.

As pointed out by Semlitsch and Bodie (2003), the long-term persistence of many amphibian populations depends on the availability of vernal (seasonal) woodland pools and the surrounding, connective forest habitat. The ability of local populations to safely disperse is critical for the survival of these species. For instance, while many species of salamanders return to where they hatched to breed and lay eggs, it has been shown that they will use other vernal pools for breeding if their vernal pool of origin has been disturbed (if it is within their migration distance capacity). Linear disturbance corridors such as roadways and pipeline right-of-ways can create impermeable barriers to movement and effectively isolate populations of these organisms from alternative breeding sites. Isolated populations are at greater risk for extirpation (local extinction). The Jefferson salamander (*Ambystoma jeffersonianum*), another species of special concern in

New York, is an example of an amphibian that will be at risk should significant forest alterations occur.

The development of shale gas infrastructure in the New York and Pennsylvania region will have profound forest fragmentation impacts. Recent modeling work performed by the Pennsylvania Chapter of The Nature Conservancy indicates that approximately 2/3^{rds} of the Marcellus well pads to be built in Pennsylvania will be located in what is currently forested habitat (TNC 2010). Coupled with the associated connective infrastructure of access roads and pipeline right-of-ways (ROWs), disruption of vital ecological processes is assured.

Fragmentation creates an increase in the amount of forest edge (the interface between forest and non-forest). This transitional zone or "ecotone" is fundamentally different in structure and functionality from an interior forest system. Edge habitat is characterized by increased light levels on the forest floor, reduced soil moisture, and a high degree of biological invasion from non-native invasive organisms. Dramatic changes can occur in the soil chemistry and associated micro biota. The top layer of the soil profile, the rich organic duff, begins to dry out and the primary decomposition community begins to shift from fungal to bacterial. Changes in the soil micro biota will result in shifts in the macro biotic community structure. The regeneration of desirable tree species (the successional trajectory) will be affected, potentially impacting the level of valuable ecosystem benefits supplied by the forest. These changes have direct economic implications to both landowners and society. Invasive species, for instance, have been estimated to cost the U.S. economy approximately $120 billion dollars per year (Pimintel et al. 2004).

Invasive organisms within terrestrial forest environments tend to be early successional species that respond favorably to site disturbance. Disruption of native plant cover and the exposure of the forest floor to sunlight provide an opportunity for these organisms to establish satellite populations. These populations eventually radiate out into the adjacent forest, displacing native species and retarding desirable tree regeneration (Bennet et al. 2011). Dispersal (vectoring) mechanisms and/or corridors are required in order for these non-native species to colonize new locations and the access roads, pipelines, and vehicular traffic associated with natural gas extraction are ideally configured to serve this function. Long beyond the point when wells are decommissioned, the landscape legacy of forest edge spreading outward from pipeline corridors, access roads, well pads, and related infrastructure will continue to disrupt ecosystem functioning as non-native organisms repeatedly colonize exposed areas and impede desirable tree regeneration.

Invasive species suppression and the eventual restoration of these disturbed sites to forested systems will require resources of a significant financial and temporal scale. While published information is scarce, it is in the professional experience of restoration practitioners in this region that the reasonable reconstruction of forest canopy and understory diversity can cost between $4,000 and $10,000 per acre. The suppression of invasive plant species is also a major, recurring expense with the initial years' treatment often costing between $1,000 and $2,500 per acre. Invasive treatment in subsequent years typically drops in cost by approximately 50% per year during the first three years of suppression. Treatment and monitoring will need to continue on an annual basis until forest canopy closure is re-established and the resulting changes in light penetration and soil conditions begin to favor native species.

As the effects of forest fragmentation may not immediately manifest themselves following the disturbance, monitoring is often suggested as a methodology to balance and modify the level of fragmenting activity in accordance with the conservation of forest-related ecosystem services. Unfortunately, these effects may not be linear in nature and thus are not always amenable to an adaptive management approach. Biological systems may possess thresholds that provide little indication of impending adverse impacts until sudden system collapse.

It is from within this conceptual framework that a review of the NYDEC Revised Draft RDSGEIS was undertaken and the following concerns identified:

Infrastructure Density-related Ecological Impacts -

- While mandatory unitization of production areas is in effect in New York, this spacing regime is geared toward maximization of gas extraction and not natural resource protection. Preliminary research results already point towards pad density as a significant indicator of potential landscape level impacts to water quality (Academy of Natural Sciences 2011). The RDSGEIS makes no mention of utilizing ecological planning units (such as the sub watershed) or ecological carrying capacity models. This is necessary to assure the industrial development pattern is consistent with the maintenance of ecological integrity.

- Density of infrastructure is also directly correlated to percent impermeable surface within subwatersheds. Increased impermeable surface area will disrupt both surface and subsurface hydrologic regimes within currently forested systems

resulting in shifts in species composition and functional benefits. For instance, it is widely accepted among watershed managers that negative changes in water quality and quantity become clearly evident when impermeable surface begins to exceed 10% of a given watershed area. The RDSGEIS-proposed mitigation strategies do not address allowable levels of impermeable surface within ecological planning units such as the subwatershed.

Forest Fragmentation

- While the requirement for ecological assessments and site-specific mitigation measures on well pads placed in grasslands of greater than 30 acres (in grassland focus areas) and for forest patches of greater than 150 acres (in forest focus areas), is helpful this approach is, in essence, ironically fragmented. It completely fails to address the importance of landscape connectivity between patches. As such, it will not protect the landscape-level ecological processes that maintain regional forest integrity. It will also fail to protect connective corridors vital to the movement of plant and animal populations in response to climate change. A preferable methodology would be to set maximum allowable levels of deforestation and fragmentation based upon ecological planning units such as the subwatershed.

- It is strongly recommended that a comprehensive, ecosystem-based plan guide the decision-making and permitting process in place of the piecemeal approach to land use planning and the protection of watershed resources set forth in the RDSGEIS. Setting maximum thresholds and spatial parameters for percent forest cover loss

and forest connectivity would assure that density levels and cumulative impacts of natural gas extraction do not exceed the ability of the regional ecosystem to absorb these activities.

- The RDSGEIS correctly emphasizes the importance of minimum patch sizes and landscape connectivity in protecting terrestrial wildlife habitat and/or the human recreation associated with such wildlife. However, no discussion or analysis is present regarding the impact that fragmentation and increasing edge habitat will have upon long term forest successional trajectory and associated biodiversity.

- No analysis has been presented in the RDSGEIS regarding the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

- Section 6.4.1.2 estimates that a mere 7% of the forest cover underlain by the Marcellus Shale in NY occurs on State-owned land. However, section 7.4.4 proposes a ban on surface disturbance within state forests and state wildlife management areas only. It is important to understand that this prohibition is not based upon any substantive ecological differences between forests under different ownership.

- Section 7.4.4 gives several reasons for prohibiting surface disturbance on State-owned land including: "Increased light and noise levels would be likely to have significant impacts on local wildlife populations, including impacts on breeding, feeding and migration" and "The local wildlife populations could take years or even

decades to recover." These concerns are equally applicable to privately-owned forests, yet full mitigation of these identified impacts to wildlife is not addressed for the remaining 93% of the forest cover in the state. In particular, noise reduction strategies are entirely omitted from section 7.4.1.1 (BMPs for Reducing Direct Impacts at Individual Well Sites).

- Section 7.4.1.1 requires full cutoff (downward) lighting only during bird migration periods. As the ecological impacts of artificial night lighting across a range of species are well documented in the scientific literature, this requirement should be extended year-round.

- Section 7.4.1.1 fails to address BMPs for placement and maintenance of gathering pipelines. As this infrastructure is fundamental to well pad development, and has the potential to disrupt a greater net acreage than the actual pad, BMP recommendations should be developed.

- Section 7.4.1.1 fails to address BMPs for placement and mitigation of compressor station impacts.

- Section 7.4.1.2 indicates that for forest patches of 150 acres or more (within Forest Focus Areas) where the DEC issues a disturbance permit after reviewing the required Ecological Assessment, "enhanced monitoring of forest interior birds during the construction phase of the project and for a minimum period of two years

following the end of high-volume hydraulic fracturing activities (i.e., following date of well completion) would be required." While this is an important recommendation, such enhanced monitoring should be extended to less mobile species sensitive to the radical changes in forest floor light and moisture levels that forest fragmentation will cause. Forest-dwelling amphibian species are at a particular risk of extirpation (local extinction) following the loss of interior forest conditions given their limited ability to traverse across linear landscape barriers such as roadways and pipeline ROWs.

- As connectivity between forest patches is critical to allowing for species migration, dispersal, and the continued genetic fitness of terrestrial species, mitigation strategies protective of this landscape level feature should be required. The RDSGEIS does not presently address protection of landscape connectivity and mitigation of disruptions to connective corridors.

- Definition of a disturbed area – clarification should be made as to the minimum size that defines a disturbed area.

- Section 7.4.1.3, *Monitoring Changes in Habitat* recommends, on parcels meeting the threshold criteria in grassland and forest focus areas, that monitoring of disturbance effects should occur during the drilling process and for a minimum of two years following well completion. While monitoring is indeed a valuable tool, effective implementation of operational changes (adaptive management) following and in

response to ecosystem disruption is not always possible. Ecosystem response to disturbance may not follow a linear pattern as previously unknown tolerance thresholds may be crossed. Sudden system collapse and the loss of valuable structural and functional features of an ecosystem may occur even in the absence of discernible advance indicators of stress. A more appropriate response would be to apply the precautionary principle and study the likely impacts prior to widespread, and potentially irreversible, landscape modification.

Invasive Species Introduction & Management

- It is recommended that section 6.4 be expanded to include an analysis of the threat potential to forest health from the inadvertent introduction and facilitation of the spread of invasive terrestrial invertebrates and pathogens. The current analysis only considers invasive plants and aquatic organisms.

- The construction of infrastructure necessary to develop the Marcellus and Utica shales will entail the movement of large fleets of vehicles and equipment from various sections of North America. It will also entail the movement of large numbers of transient laborers and technical personnel from across the United States. This activity carries an inherent risk of acting as a vectoring mechanism for a number of threats to forest health. The RDSGEIS should review this potential mechanism of invasive threat and propose mitigation strategies.

- Section 6.4 should also be expanded to include an analysis of the impact that massive increases in forest edge habitat will have upon the incursion and establishment of invasive plant species. Edge habitat is inherently attractive to the type of plant species that display invasive characteristics. Invasive plants tend to be early successional species adapted to disturbed sites. The ecotone between forest and grassland is an area generated by recent disturbance and thus presents ideal conditions for these opportunistic, rapidly-reproducing species. Periodic re-infestation of edge habitat by invasive plant species is also highly probable given the high light levels and frequent deposition of wind-borne and bird-deposited seeds in such areas. The creation of edge habitat on the scale anticipated by natural gas infrastructure is likely to result in chronic, regional infestations of undesirable species that will require regular, and expensive, control interventions. The creation of forest edge is, in and of itself, an important precursor to biological invasion.

- Section 7.4.2.1 fails to include compressor stations and pipeline ROWs in the requirements for invasive species best management practices.

- Section 7.4.2.1 indicates that an invasive species survey "should be conducted by an environmental consultant familiar with the invasive species in New York." It is recommended that the word "should" be replaced by "must".

- It is recommended that the invasive species survey required under section 7.4.2.1 stipulate that percent aerial cover be classified <u>for each</u> identified invasive plant

species on the site. Identification of baseline infestation levels is critical to determining target levels of cover reduction and control.

- Section 7.4.2.1 fails to provide any measurable metric, such as percent cover reduction from pre-disturbance levels, for quantifying levels of invasive control. The recommendation strategy that, "Any new invasive species occurrences found at the project location should be removed and disposed of appropriately" should be qualified to include the latent seed bank in the soil.

- Section 7.4.2.1 fails to define the temporal timeframe of responsibility for invasive suppression. The seeds of many invasive plant species can lie dormant in the soil for years. This latent seed bank creates a reservoir for future outbreaks following soil disturbance. It is critical that a long term monitoring and treatment program be implemented for all sites and associated infrastructure. Monitoring and suppression treatments should continue until final site reforestation and effective closure of the tree canopy.

- Section 7.4.2.1 fails to provide a spatial framework for the area of invasive species control responsibility. Invasive species are highly mobile and akin to a wildfire in their dispersal from initial point of infestation. At a minimum, site developers should be required to manage invasive infestations within all forest edge environments surrounding new pads, pipeline ROWs, and newly constructed access roads. Failure to do so will result in migration of these species off-site and the transfer of the financial burden of control onto adjacent property owners.

- As prevention is more cost effective than control, requirements should be adopted mandating independent site inspections by a qualified ecologist on no less than a semiannual basis until final reforestation and canopy closure occurs. Failing to provide for frequent site inspections assures compliance will be minimal.

Site Restoration

- The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline ROWs and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is NOT restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not "restoration". It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

- Restoration objectives and planning should be integrated into best management practices and developed based upon a landscape-level analysis. Re-establishing forest connectivity should be a primary goal.

- As the service life of gas extraction infrastructure such as transmission pipelines may extend for decades, mitigation banks and sites where restoration of previously degraded systems might off-set the disturbance for the interim period should be utilized. This will help assure that no net loss of ecosystem benefits occurs within the region.

- Requirements for an independent, qualified restoration ecologist to oversee and inspect site restoration should be developed in order to assure effective compliance.

Summary

As currently proposed, the NYDEC RDSGEIS does not provide an adequate assessment of likely impacts associated with the rapid conversion of forested and rural ecosystems to industrial sites. It also fails to recommend potential mitigation strategies and options that would offset and reduce the "significant" impacts anticipated for native terrestrial ecosystems. Protection of these terrestrial ecosystems is critical to the continued health of the regions' aquatic resources. Inadequate attention has been given to the following vital considerations: density related impacts of infrastructure, forest fragmentation, invasive species, and site restoration. Should the RDSGEIS be adopted in its current form, widespread disruption to forest ecosystems within the upper Delaware River Basin and other watersheds underlain by the Marcellus and Utica formations will occur. Restoration of these systems following the eventual cessation of natural gas extraction will be a monumental cost incurred by both the taxpaying public and adjacent private property owners. It is strongly recommended that the NYDEC

consider a more comprehensive approach to protecting the integrity of the forested landscapes in New York. Setting maximum thresholds and spatial parameters for percent forest cover loss, forest connectivity, and core forest integrity within ecological planning units, such as the subwatershed, would assure that density levels and cumulative impacts of natural gas extraction do not exceed the ability of the regional ecosystem to absorb these activities.

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Attachment 9

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January 8, 2012

Re: Comments on the RDSGEIS on NY Marcellus Shale Natural Gas Hydraulic Fracturing

These comments are submitted regarding the Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) governing high-volume, hydraulic fracturing as a method of natural gas drilling in the Marcellus Shale and similar formations in New York State.

I am Senior Scientist in the Health and Environment Program at the Natural Resources Defense Council in New York City, and Assistant Clinical Professor in the Department of Environmental Health Sciences at the Mailman School of Public Health of Columbia University. I received my doctorate in Public Health from Columbia University, and much of my research considers the effects of climate change on human health (my CV is attached). These comments relate to climate change and public health concerns raised by the information described in the RDSGEIS.

Although the RDSGEIS describes greenhouse gas emissions that would be generated by Natural Gas Hydraulic Fracturing operations in the Marcellus and other shale formations in NY State (sec. 6.6), and the means to reduce those health-harming emissions (sec. 7.6), the RDSGEIS lacks critical information about the exacerbating effect climatic changes will have on the uncertainties of drilling operations. Further, climate change is likely to increase the risk to public health from HVHF operations if these operations are conducted without regard to the effects of climate change on the environmental context of drilling operations.
Climate change is likely to increase several key uncertainties in shale gas natural gas hydraulic fracturing operations which are not addressed in the RDSGEIS, yet should be. Several of these climate change and public health-relevant omissions are described below:

1. **More frequent extreme rainfall events.** The public health risks of drill pad operations and waste fluid disposal are likely to be affected by more frequent extreme rainfall events in New York State, as climate change continues. These events and the flooding they can cause need to be factored into the RDSGEIS. Measured changes in the heaviest precipitation events in the Northeastern US increased 67% over the period 1958-2007; and the trend toward heavier precipitation is projected to increase into the 2090s.[1] In New York State in the last 60 years from 1948 to 2006, there has been a statistically significant 56% increase in the most extreme rainfall events, according to the a 2007 study by Environment America.[2] As climate change continues, these extreme rainfall events are projected to continue to occur more frequently.[3] The New York Panel on Climate Change (or NPCC), an expert group of university researchers and climate modelers, investigated climate change's effects on New York City and the surrounding region, and projected that annual precipitation in the New York region will "more likely than not" increase, with mean annual precipitation increasing up to 5% by the 2020s, 10% by the 2050s, and

5-10% by the 2080s.[4] The New York State Climate Action Council's Nov. 2010 *Climate Action Plan Interim Report* noted in its Executive Summary (ES) that, "Summertime rain is expected to fall more often as heavy downpours, leading to more flooding; at the same time, the periods between these rainstorms are likely to be drier, leading to droughts. … Public and private entities will need to assess whether new investments in infrastructure, particularly long-lived infrastructure like power plants and transportation, will be consistent with a low-carbon future, both in terms of GHG emissions and in terms of vulnerability to a changing climate. We should avoid investments that are not highly adapted to a modified climate, such as infrastructure sited in low-lying floodplains."[5] ***DEC should act consistently with the recommendations of the New York Climate Action Plan Interim Report by prohibiting HVHF operations and infrastructure in low-lying areas***.

2. **Changes in floodplain location.** The locations of 50-, 100- and 500-year floodplains are likely to change in New York State, owing to the effects of climate change. Extreme rainfall events are becoming more frequent in the US.[6] This trend was also noted in the recently-released NY State ClimAID report: "Intense precipitation events (heavy downpours) have increased in recent decades, and are likely to increase in future."[7] These extreme precipitation events are occurring in tandem with a long-term increase in annual average precipitation of 0.37 inches per decade since 1900.[8] The advent of extreme precipitation events taken together with a general increase in average precipitation is likely to alter the location and size of floodplains. Altered floodplain locations could dramatically compromise the siting and safety of drilling operations, as well as waste disposal and transport. With the trend to heavy downpours over the past 50 years projected to continue, an increase in localized flash flooding in hilly regions across the state is expected. "Flooding has the potential to increase pollutants in the water supply and inundate wastewater treatment plants and other vulnerable development within floodplains."[9] The most recent state of the science on the effects of climate change on the extent of local floodplains should be applied in the RDSGEIS's consideration of the potential impacts of proposed new drilling in NY State.

   Because increasingly frequent and extreme rainfall events could threaten drilling infrastructure, operations and disposal, such investments should be avoided without a full, detailed mapping of areas at greatest risk from storm and flood damage. This is in line with the Nov. 2010 recommendations of the NY State Climate Action Council in their Climate Action Interim Report.[10] Floodplain maps must be fully updated to include the latest information on how climate change will affect local flood plain locations, taken from downscaled climate model projections.[11]

   Although DEC proposes prohibiting surface disturbances in 100-year floodplains[12], this approach is problematic for several reasons. First, DEC should also prohibit subsurface activity in these areas. Second, the prohibition should apply to additional matters involved in HVHF, such as the siting of pipelines and other potentially sensitive infrastructure, the construction of impoundment ponds, the location of temporary waste storage tanks, etc. Third, not only does DEC acknowledge that FEMA is currently updating Flood Insurance Rate Maps (FIRMs) in several high-flood areas in the state,[13]

but the Department also admits that the increased frequency and magnitude of flooding has raised a concerns regarding the reliability of the existing FIRMs in the Susquehanna and Delaware River basins.[14] Given this acknowledgment, DEC should extend this prohibition to 500-year floodplains. In general, ***no permits should be issued anywhere in the state before updated floodplain maps are in place for the entire region and these maps are reflected in DEC's environmental review and regulations***. These maps should be reflective of anticipated changes that may result from climate change, namely the increase in frequency and severity of storm events. To permit any activities before properly mapping prohibited areas is inconsistent with SEQRA.

3. **Potential changes in groundwater flow patterns.** Hydrological assumptions about groundwater flow patterns through the Marcellus and other shale formations could be altered by water demands from drilling activities, if coupled with increasingly frequent seasonal drought and/or flood periods in NY State, as climatic instability increases. More frequent alternation between periods of extreme wet and dry periods could, over time, result in changes in groundwater flow patterns[15] and unanticipated movement of production fluids and other groundwater in subsurface fractures and fissures. While challenging to predict, such migration could threaten drinking water supplies. Subsurface hydrological modeling studies have been undertaken to account for some of these climate change effects,[16] yet such studies were ignored by the RDSGEIS. ***No permits to drill near groundwater resources should be issued until climate change-based subsurface hydrological modeling studies have been incorporated into the DEC's review and regulations***.

4. **Changing seasonal precipitation patterns.** Increasing temperatures have already caused spring snowmelt to occur earlier in the year, and climate change will continue to bring changing patterns of seasonal precipitation across the state, with more annual precipitation falling as rain rather than snowfall.[17] This could affect the frequency, intensity and timing of overland flooding events at drill pad sites. In 2011, Hurricane Irene caused extensive flooding across the Catskills and upstate NY, in part because the soils were already so saturated from record-breaking heavy precipitation during the summer. As the USGCRP 2009 report attests, "…water-saturated soils can generate floods with only moderate additional precipitation."[18] In addition to prohibiting water withdrawals during low stream flow, ***the RDSGEIS should explicitly address shifting precipitation patterns resulting from climate change, increased flooding risks, and the public health issues they may create***.

5. **Increasing temperatures could exacerbate chemical volatilization and fugitive emissions from drill sites.** Ambient temperatures are projected to increase across NY State, due to the warming climate.[19] Volatilization of fracking chemicals and fugitive emissions may increase due to higher evaporation rates from higher temperatures. Exposures to workers and the community could increase, exacerbating associated health risks. ***Adverse human health impacts resulting from increased volatilization of fracking chemicals and fugitive emissions should be explicitly addressed in the RDSGEIS.***

6. **Conflicting demands on water use during drought periods are likely to be exacerbated by climate change.** Hydrofracking operations will require enormous quantities of water in drilling, in operations, and as wastewaters are disposed of. Marcellus development is projected over a thirty-year life cycle.[20] The average year would see 1,600 or more wells.[21] The amount of water consumed in each well is projected between 2.4 and 7.8 million gallons,[22] and the average well consumes 4.2 million gallons of water.[23] Based on these numbers, approximately 201,600,000,000 gallons of freshwater will be permanently removed from New York State surface and groundwater sources for the purpose of HVHF operations. The effect of these freshwater diversions in light of predicted climate change impacts to water supplies was not analyzed in the RDSGEIS. Because climate change is likely to disrupt the timing of precipitation's seasonality, the enormous water demands from hydrofracking operations could periodically conflict, during periods of local drought, with those of populations who rely on local surface and groundwater sources for drinking, domestic, municipal, business and agricultural uses. ***The potential for conflicts between HVHF operators and the public over dwindling water supplies resulting from climate change, including the adverse environmental and human health impacts associated with unprecedented freshwater diversions, should be examined in the RDSGEIS, and operators should be prohibited from consuming water from underground, surface, and municipal sources if doing so would exacerbate local drought conditions.***

7. **Nitrous oxide is an extremely potent GHG that the RDSGEIS fails to properly analyze.** Even in its current discussion of greenhouse gases (GHG) generated during drilling operations, the RDSGEIS lacks sufficient information in Sec. 6.6.2 about nitrous oxide (N_2O) as a greenhouse gas (GHG) of concern. The RDSGEIS states that because N_2O is produced in small quantities it need not be explicitly discussed in terms of its treatment or disposal.[24] However, N_2O has a global warming potential 289 times greater than carbon dioxide (CO_2), and an atmospheric lifetime 114 times longer than CO_2.[25] It is injudicious to entirely negate N_2O's effect on climate change in the RDGEIS without fuller discussion of the volumes that would be generated, from what sources, and potential treatment methods. ***The RDSGEIS should identify the impacts associated with N_2O emissions and proposed mitigation measures to curb these emissions.***

8. **Public health impacts.**. Climate change impacts can jeopardize the safety of drilling operations and exacerbate the consequences of HVHF operations on New York State, leading to adverse environmental human health impacts. ***DEC should conduct a comprehensive Health Impact Assessment (HIA) as part of the state's environmental review*** in order to evaluate potential risks to human health from gas development in New York, including the dynamic between HVHF operations (impacts on water quantity and quality, waste runoff, air pollution, etc.) and climate change (water shortages, floods, temperature rise, etc.). ***To assist in the review of comments received, at least one Public Health professional should sit on the team who evaluates the comments received by DEC on the RDGEIS***. Their expertise would be helpful in assessing other potential areas of significant health concern, ranging from air quality, water quality, worker exposure, waste management, etc...

Based on the foregoing, the RDSGEIS is incomplete in its current form. The RDSGEIS is deficient because it does not ever come to grips with the challenges to safe HVHF operations posed by climate change: it does not consider changes in the frequency of extreme rainfall events, changes in floodplain location, changes in groundwater flow patterns, changes in seasonal precipitation patterns, changes in average temperature, potential water use conflicts, the effects of nitrous oxide on climate change, or the public health impacts of climate change in association with HVHF operations. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which will pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

Thank you for consideration of these comments.

Respectfully,

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[23] 2011 RDSGEIS, Cumulative Water Withdrawal Impacts, 6.1.1.7, p. 6-10.

[24] 2011 RDSGEIS, Emissions from Oil and Gas Operations, 6.6.2, p. 6-188.

[25] 2007 Intergovernmental Panel on Climate Change (IPCC), Fourth Assessment Report (AR4), Working Group 1 Technical Summary, Chapter 2, p.212, "Changes in Atmospheric Constituents and Radiative Forcings."

Attachment 10

Gina Solomon, M.D., M.P.H

MEMORANDUM

TO: Kate Sinding
FROM: Gina Solomon, M.D., M.P.H., Senior Scientist, NRDC; Clinical Professor of Health Sciences, UCSF
DATE: January 9, 2011
RE: NRDC Comments on RDSGEIS, NY Marcellus Shale Natural Gas Hydraulic Fracturing relative to Public Health concerns and Health Impact Assessments

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, including air pollution, potential contamination of groundwater or surface water that may be used for drinking or recreation, toxicity of chemicals used in fracturing fluids, safety concerns such as fire or explosion, increased vehicle traffic, altered social conditions, and the health effects of noise, vibration, and light at night. The RDSGEIS addresses some aspects of a subset of these health issues, but fails by (1) omitting several important health issues entirely, (2) addressing only some aspects of other issues such as air, water quality and traffic without fully considering the health impacts in those areas (Note: this issue is addressed more fully in comments on those sections of the RDSGEIS submitted as part of this package), and (3) failing to consider health issues as a group in a formal Health Impact Assessment (HIA), including the interactive effects on the health of local residents and communities.

The failure to conduct a full HIA as part of the RDSGEIS is an important omission because the health effects of numerous chemicals used and emitted in the course of natural gas development have been well-described.[1] In addition, there are already numerous reports of health complaints among people who live near natural gas drilling and fracturing operations in other states. These health complaints have received coverage in the media,[2] and some cases have been investigated by researchers or government agencies.[3] Reported health issues in residents near natural gas drilling operations include: eye irritation, dizziness, nasal and throat irritation, sinus disorders, bronchitis and other respiratory symptoms, depression, nausea, fatigue, headaches, anxiety, difficulty concentrating, and a range of other symptoms.[4] Just last week, the nation's top environmental health expert

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[1] Colborn, T.; Kwiatkowski, C.; Schultz, K., and Bachran, M. Natural gas operations from a public health perspective. Human & Ecological Risk Assessment. 2011; 17(5):1039-1056. http://www.endocrinedisruption.com/chemicals.journalarticle.php. Accessed January 9, 2011; Witter R, Stinson K, Sackett H, et al. Potential Exposure-Related Human Health Effects of Oil and Gas Development: A White Paper. University of Colorado Denver, Colorado School of Public Health, Denver, Colorado, September 15, 2008. Witter R, Stinson K, Sackett H, et al. Potential Exposure-Related Human Health Effects of Oil and Gas Development: A Literature Review (2003-2008) University of Colorado Denver, Colorado School of Public Health, Denver, Colorado, August 1, 2008. http://docs.nrdc.org/health/hea_08091702.asp. Accessed January 9, 2011.

[2] See eg. ProPublica. Science Lags as Health Problems Emerge Near Gas Fields. http://www.propublica.org/article/science-lags-as-health-problems-emerge-near-gas-fields/single. Accessed January 3, 2012.

[3] See eg. ATSDR Health Consultation. Garfield County. http://www.atsdr.cdc.gov/hac/pha/Garfield_County_HC_3-13-08/Garfield_County_HC_3-13-08.pdf. Accessed January 3, 2012; Subra W. Health Survey Results of Current and Former DISH/Clark, Texas Residents. Earthworks, Dec 17, 2009. http://www.earthworksaction.org/library/detail/health_survey_results_of_current_and_former_dish_clark_texas_residents/. Accessed January 3, 2012.

[4] Ibid.

affirmed his view that more research is necessary regarding the impacts of natural gas drilling on human health.[5] Although much research needs to be done to investigate specific associations between the reported symptoms and nearby gas extraction operations, there is sufficient information on health issues associated with the chemicals and other environmental stressors at these sites to demand performance of a full HIA.

> *Health impact assessment is a systematic process that uses an array of data sources and analytic methods and considers input from stakeholders to determine the potential effects of a proposed policy, plan, program, or project on the health of a population and the distribution of those effects within the population. Health impact assessment provides recommendations on monitoring and managing those effects.*
>
> National Research Council, 2011

Rationale for a Health Impact Assessment in New York State

In September 2011, the National Research Council of the National Academies of Science (NAS) issued a report entitled: *Improving Health in the United States: The Role of Health Impact Assessment*. The report recommended the greater use of HIA in decision making in the United States, saying that: "systematic assessment of the health consequences of policies, programs, plans, and projects is critically important for protecting and promoting public health; as indicated, lack of assessment can have many unexpected adverse health (and economic) consequences."[6]

According to the Centers for Disease Control and Prevention (CDC), the HIA framework is used to bring potential public health impacts and considerations to the decision-making process for plans, projects, and policies that fall outside of traditional public health arenas, such as transportation and land use.[7] The National Environmental Policy Act (NEPA) requires federal agencies to consider the environmental impact of their proposed actions on social, cultural, economic, and natural resources prior to implementation. In New York, the State Environmental Quality Review Act (SEQRA) regulations [see 617.2(l)] define Environment as: "…the physical conditions that will be affected by a proposed action, including land, air, water, minerals, flora, fauna, noise, resources of agricultural, archeological, historic or aesthetic significance, existing patterns of population concentration, distribution or growth, existing community or neighborhood character, and *human health*" (emphasis added).[8]

In the United States, HIA is a rapidly emerging practice. HIA is also regularly performed in Europe and Canada. Some countries have mandated HIA as part of a regulatory process. In the U.S., some version of an HIA is arguably required by NEPA and by many state "mini-NEPAs,"[9] including most explicitly, the New York SEQRA,

[5] CDC scientist: tests needed on gas drilling impact. Associated Press. January 4, 2012. http://online.wsj.com/article/AP8338b702930849f49d22a5d96b7d1b2d.html. Accessed January 5, 2012.
[6] National Research Council. Improving Health in the United States: The Role of Health Impact Assessment. Washington, DC: The National Academies Press, 2011, pp. 4-5.
[7] Centers for Disease Control and Prevention. http://www.cdc.gov/healthyplaces/hia.htm. Accessed January 3, 2012.
[8] See also Environmental Conservation Law § 8-0103(5) ("…it is the intent of the legislature that the government of the state take immediate steps to identify any critical thresholds for the health and safety of the people of the state and take all coordinated actions necessary to prevent such thresholds from being reached).
[9] Bhatia, R and Wernham, A. Integrating Human Health into Environmental Impact Assessment: An Unrealized Opportunity for Environmental Health and Justice. Environmental Health Perspectives. 2008;116(8): 991-1000.

which clearly specifies the mandate for a full characterization of the effects on human health. The National Academies of Science committee on HIA recommended: "improving the integration of health into EIA under NEPA and related state laws…[to] serve the mission of public health and the goals of HIA….[In order t]o ensure reasonable priority of health issues under NEPA, public-health agencies should be afforded a substantive role in the scoping and oversight of health-effects analysis in EIA, and health-effects analysis must be afforded resources commensurate with the task.[10]

There is precedent for performing formal HIAs for drilling activities. In 2007, an HIA of proposed oil and gas development projects in Alaska's North Slope was performed by the local government.[11] The HIA evaluated predicted impacts on fish and wildlife and the consequences for diet and health in the local population. It also identified potential social changes such as drug and alcohol use. The HIA led to new requirements for air quality analysis and monitoring of any oil-related contaminants in subsistence foods, and to a new requirement for worker education on drugs, alcohol and sexually transmitted diseases.

A draft HIA was done in Colorado for a proposed gas drilling development in Battlement Mesa. This draft HIA identified eight major areas of health concern (stressors) associated with natural gas development and production: air emissions, water and soil contaminants, truck traffic, noise/light/vibration, health infrastructure, accidents and malfunctions, community wellness, and economics/employment.[12] Several physical health outcomes linked to potential exposures were considered, including respiratory, cardiovascular, cancer, psychiatric, and injury/motor vehicle-related impacts on vulnerable and general populations in the community. The study concluded: "The key findings of our study are that [the] health of the Battlement Mesa residents will most likely be affected by chemical exposures, accidents or emergencies resulting from industry operations and stress-related community changes."[13] The researchers went on to recommend a set of mitigation measures to reduce the health threats to local residents. Although the Battlement Mesa HIA was halted by the local Board of County Commissioners, apparently for political reasons,[14] it demonstrated the feasibility and utility of HIA for evaluating risks to the health of local residents from hydraulic fracturing and natural gas drilling operations.

In October of 2011, hundreds of health professionals signed a letter to Governor Cuomo specifically requesting that the draft SGEIS be "supplemented to include a full assessment of the public health impacts of gas

[10] National Research Council. Improving Health in the United States: The Role of Health Impact Assessment. Washington, DC: The National Academies Press, 2011, p. 111-113.
[11] Wernham A. Building a Statewide Health Impact Assessment Program: A Case Study from Alaska. Northwest Public Health. Fall/Winter 2009; Health Impact Project. Case Study: Oil Development of Alaska's North Slope. http://www.healthimpactproject.org/resources/case-study-oil-development-of-alaskas-north-slope. Accessed January 5, 2011.
[12] Witter R, McKenzie L, Towle M, et al. Health Impact Assessment for Battlement Mesa, Garfield County Colorado. Colorado School of Public Health, University of Colorado, Denver, September 2010. http://www.garfield-county.com/public-health/documents/1%20%20%20Complete%20HIA%20without%20Appendix%20D.pdf. Accessed January 4, 2012.
[13] Battlement Mesa Health Impact Assessment (2nd Draft). March 1, 2011. http://www.garfield-county.com/public-health/battlement-mesa-health-impact-assessment-draft2.aspx. Accessed January 4, 2012.
[14] Vote Ends work on Battlement Mesa HIA. May 4, 2011. http://www.healthimpactproject.org/news/in/vote-ends-work-on-battlement-mesa-hia. Accessed January 4, 2012.

exploration and production."[15] The letter pointed out that, "there is a growing body of evidence on health impacts from industrial gas development," and specifically stated that: "A comprehensive Health Impact Assessment (HIA) would be the most appropriate mechanism for this work." The Director of the Agency for Toxic Substances and Disease Registry (ATSDR), Dr. Christopher Portier, also supports more thorough assessment of the health impacts of gas drilling, stating: "Studies should include all the ways people can be exposed, such as through air, water, soil, plants and animals."[16]

In summary, the requirements of SEQRA and recommendations of the National Academies of Science argue strongly for the need for a New York HIA of the health impacts of gas drilling and hydraulic fracturing. A similar investigation in Colorado revealed a set of potentially significant human health impacts associated with chemical exposures, accidents, and stress-related community changes, all of which were insufficiently considered in the New York RDSGEIS. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

[15] Abramson A, Abrams J, Alexander M, et al. Letter to The Honorable Andrew M. Cuomo. October 5, 2011. http://www.psehealthyenergy.org/resources/view/198813. Accessed January 5, 2012.
[16] CDC scientist: tests needed on gas drilling impact. Associated Press. January 4, 2012. http://online.wsj.com/article/AP8338b702930849f49d22a5d96b7d1b2d.html. Accessed January 5, 2012.

Attachment 11

Briana Mordick

January 10, 2012

To: Kate Sinding

From: Briana Mordick

Subject: Technical analysis of hydraulic fracturing-induced seismicity provisions in the New York State Revised Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program

Introduction

The following report is a technical review and analysis of the hydraulic fracturing-induced seismicity provisions of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. This report includes recommendations for properly managing the risks associated with induced seismicity.

Analysis

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments, concluding that,

"There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. Information reviewed indicates that there is essentially no increased risk to the public, infrastructure, or natural resources from induced seismicity related to hydraulic fracturing. The microseisms created by hydraulic fracturing are too small to be felt, or to cause damage at the ground surface or to nearby wells. Accordingly, no significant adverse impacts from induced seismicity are expected to result from high-volume hydraulic fracturing operations."[1]

Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. In a report commissioned by United Kingdom-based Cuadrilla Resources, researchers concluded that a series of earthquakes in Lancashire, UK were likely caused by hydraulic fracturing. Two relatively large earthquakes, with magnitudes 2.3 and 1.5, and 48 smaller events occurred in the hours after several stages of the Preese Hall 1 well were fracked.[2] A separate report written by a seismologist at the Oklahoma Geological Survey concluded that a swarm of about 50 earthquakes in Garvin County, Oklahoma, ranging in magnitude from 1.0 to 2.8, could also have been induced by hydraulic fracturing.[3]

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[1] Revised Draft SGEIS 2011, Executive Summary, Page 19

[2] de Pater, C.J., and Baisch, S., 2011, *Geomechanical Study of Bowland Shale Seismicity: Synthesis Report*, prepared for Cuadrilla Resources Ltd, 71p., available at: http://www.cuadrillaresources.com/cms/wp-content/uploads/2011/12/Final_Report_Bowland_Seismicity_02-11-11.pdf

[3] Holland, A., 2011, *Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma*, Oklahoma Geological Survey, Open-File Report OF1-2011, 31p., available at: http://www.ogs.ou.edu/pubsscanned/openfile/OF1_2011.pdf

The RDSGEIS concedes that, "There are no seismic monitoring protocols or criteria established by regulatory agencies that are specific to high volume hydraulic fracturing,"[4] and recognizes that, "It is important to avoid injecting fluids into known, significant, mapped faults when hydraulic fracturing."[5] However, instead of developing such protocols and requiring operators to demonstrate that they have accounted for seismic risks in the siting of wells and design of hydraulic fracture treatments, the RSDGEIS assumes that, "Generally, operators would avoid faults because they disrupt the pressure and stress field and the hydraulic fracturing process,"[6] and, "It is in the operator's best interest to closely control the hydraulic fracturing process to ensure that fractures are propagated in the desired direction and distance and to minimize the materials and costs associated with the process."[7]

To justify why no additional analysis or monitoring is required to prevent induced seismicity, the RDSGEIS states, "The routine microseismic monitoring that is performed during hydraulic fracturing serves to evaluate, guide, and control the process and is important in optimizing well treatments,"[8] and, "Monitoring beyond that which is typical for hydraulic fracturing does not appear to be warranted, based on the negligible risk posed by the process and very low seismic magnitude."[9] However, earlier in the document, NYSERDA's consultant ICF International concludes that, "…fracture monitoring by [microseismic fracture mapping] is **not regularly used** because of cost…"[10] So in fact, seismic monitoring would rarely be employed during a routine hydraulic fracture treatment.

The RDSGEIS further assumes that no additional analysis of seismic risk is needed due to the fact that, "The locations of major faults in New York have been mapped (Figure 4.13) and few major or seismically active faults exist within the fairways for the Marcellus and Utica Shales."[11] There are two fatal flaws with this assumption. First, in both the UK and Oklahoma incidents, the earthquakes likely occurred due to slippage on minor, sub-seismic faults. Therefore, knowing the locations of only "major faults" is not sufficient to assess the potential risk of induced seismicity from hydraulic fracturing. Second, it is precisely the injection of fluids which induces previously inactive faults to become active. Therefore, whether a fault is currently or even recently seismically active is not sufficient to predict whether it could become active due to human activity – the definition of induced seismicity. A paper on earthquake hazards from deep well injection prepared by the U.S. Geological Survey for the U.S. Environmental Protection Agency concludes that predicting and mitigating seismic hazard risks in the Eastern United States is particularly problematic, as the causes of natural earthquakes and location of faults are not well understood.[12]

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[4] Revised Draft SGEIS 2011, Page 6-322
[5] Id.
[6] Id.
[7] Revised Draft SGEIS 2011, Page 6-323
[8] Revised Draft SGEIS 2011, Page 6-323
[9] Revised Draft SGEIS 2011, Page 6-328
[10] Revised Draft SGEIS 2011, Page 5-88, emphasis added
[11] Revised Draft SGEIS 2011, Page 6-327
[12] Nicholson, C., and Wesson, R., 1990, *Earthquake Hazard Associated With Deep Well Injection – A Report to the U.S. Environmental Protection Agency*, U.S. Geological Survey Bulletin 1951, 86p., available at: http://pubs.usgs.gov/bul/1951/report.pdf

Induced seismicity could result in unwanted and dangerous consequences, depending on the size and location of the earthquake. Fault movement may potentially endanger groundwater by creating or enhancing migration pathways between the zone being hydraulically fractured and underground sources of drinking water. Seismicity can also compromise wellbore integrity. The induced seismicity event in the UK caused ovalization of the production casing over hundreds of feet, with more than a half-inch of ovalization occurring over an approximately 250 foot length.[13] Such damage could compromise the cement bond, allowing methane or fluids to migrate up the back side of the casing to groundwater.

Even a relatively small earthquake could cause damage over a large area. The USGS report cited above states that, "Earthquakes in the Central and the Eastern United States typically cause damage over much larger areas as compared to earthquakes of the same size in the Western United States. This is primarily the result of the lower attenuation of seismic waves in the East versus the West, but other factors also may be involved."[14] Earthquakes could cause property damage including to private homes and public buildings and could also put at risk the aqueducts, tunnels, and infrastructure that deliver the New York City drinking water supply. In a report prepared for the New York City Department of Environmental Protection, environmental engineering firm Hazen and Sawyer concluded that, "…liner cracks can be anticipated to develop as the tunnels age, due to normal geologic activity (e.g., seismic activity), and to changes in subsurface conditions associated with widespread hydrofracturing, gas reservoir depletion/withdrawal and injection well operation," and, "Detrimental effects [to tunnel liners] could include liner cracks, which would facilitate infiltration of pressurized fluids."[15] In addition to natural seismic activity, induced seismicity could also be expected to create additional liner cracks. The authors also concluded that, "Hydraulic fracturing operations in proximity to the naturally occurring fracture systems that intersect DEP tunnels will increase the risk of (a) contaminating drinking water with drilling and fracturing chemicals and poor quality formation water; (b) methane accumulation around and within DEP subsurface infrastructure; and (c) tunnel liner structural failure. Mitigation of risks to drinking water quality and infrastructure integrity will require revision of current setback provisions to reflect the occurrence of laterally extensive subsurface faults, fractures, and brittle structures."[16] If earthquakes are induced along faults that intersect the DEP tunnels, these risks could be further exacerbated.

Even in the absence of actual damage, induced seismic events will have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed.

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[13] Id. at 2
[14] Id. at 13
[15] Hazen and Sawyer, 2009, *Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed: Final Impact Assessment Report,* prepared for New York City Department of Environmental Protection, 100p., available at: http://www.nyc.gov/html/dep/pdf/natural_gas_drilling/12_23_2009_final_assessment_report.pdf
[16] Id., Appendix D

The RDSGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary.

Recommendation

The RDSGEIS should require operators to provide a site-specific analysis of the risk of induced seismicity due to hydraulic fracturing. This should include a detailed analysis of the geology, including the locations of known faults and an assessment of the seismic history of the region. Operators should be required to provide an analysis detailing the maximum magnitude of an earthquake that could be triggered based on anticipated injection volume and the probability that such an earthquake may occur based on site-specific geologic and geophysical parameters such as fault and fracture density, lithology, minimum horizontal stress, and anticipated pore pressure as a result of fluid injection.[17] Operators should then be required to use this data to properly design their hydraulic fracture treatment to reduce the risk of triggering induced seismicity. Operators should be required to perform seismic monitoring during hydraulic fracturing to ensure that any seismicity that occurs is within design parameters.

[17] See, e.g., Shapiro,S. A., C. Dinske, and J. Kummerow (2007), Probability of a given magnitude earthquake induced by a fluid injection, Geophys. Res. Lett., 34, L22314, doi:10.1029/2007GL031615.

Attachment 12

Expert Resumes

Harvey Consulting, LLC.

- Susan Harvey

Tom Myers, Ph.D.

Glenn Miller, Ph.D.

Ralph Seiler, Ph.D.

Meliora Design, LLC.

- Michele Adams, P.E.
- Ruth Sitler, P.E.

The Louis Berger Group, Inc.

- Niek Veraart, AICP, ASLA
- Raed EL-Farhan, Ph.D.
- Hope Luhman, Ph.D., RPA
- Edward Samanns, PWS, CE
- Leo Tidd
- Dane Ismart

Kevin Heatley

Kim Knowlton, DrPH

Gina Solomon, M.D.

Briana Mordick

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Susan L. Harvey, Owner

Susan Harvey has 25 years of experience as a Petroleum and Environmental Engineer, working on oil and gas exploration and development projects. Ms. Harvey is the owner of Harvey Consulting, LLC, a consulting firm providing oil and gas, environmental, regulatory compliance advice and training to clients. Ms. Harvey held engineering and supervisory positions at both Arco and BP including Prudhoe Bay Engineering Manager and Exploration Manager. Ms. Harvey has planned, engineered, executed and managed both on and offshore exploration and production operations, and has been involved in the drilling, completion, stimulation, testing and oversight of hundreds of wells in her career. Ms. Harvey's experience also includes air and water pollution abatement design and execution, best management practices, environmental assessment of oil and gas project impacts, and oil spill prevention and response planning. During Governor Knowles Administration, Ms. Harvey headed the Industry Preparedness Program for the Alaska Department of Environmental Conservation, Division of Spill Prevention and Response; she was responsible for oil spill prevention and response oversight of all Alaska industry operations that produce, store or transport hydrocarbons. Ms. Harvey taught air pollution control engineering courses at the University of Alaska in the Graduate Engineering Program.

Education Summary:

Environmental Engineering	Petroleum Engineering
Masters of Science	**Bachelor of Science**
University of Alaska Anchorage	University of Alaska Fairbanks

Consulting Services:

- Oil and gas, environmental, regulatory compliance advice and training
- Oil spill prevention and response planning
- Air pollution assessment and control

Employment Summary:

2002-Current	Harvey Consulting, LLC., Owner
2005-Current	Harvey Fishing, LLC., Co-owner
2002-2007	University of Alaska at Anchorage Environmental Engineering Graduate Level, Adjunct Professor
1999-2002	State of Alaska, Department of Environmental Conservation Environmental Supervisory Position
1996-1999	Arco Alaska Inc. Engineering and Supervisory Positions held
1989-1996	BP Exploration (Alaska), Inc. Environmental, Engineering, and Supervisory Positions held
1987-1989	Standard Oil Production Company *(purchased by BP in 1989),* Engineering Position
1985-1986	Conoco, Production Engineer and New Mexico Institute of Mining and Technology Petroleum Research & Recovery Center, Laboratory Research Assistant

Harvey Consulting, LLC
PO Box 771026 Eagle River, Alaska 99577
Email:sharvey@mtaonline.net; Phone: (907) 694-7994; Fax: (907) 694-7995

Employment Detail:

2002-Current **Harvey Consulting, LLC.**
Owner of consulting business providing oil and gas, environmental, regulatory compliance and training to clients.

2005-Current **Harvey Fishing, LLC.**
Co-owner and operator of a commercial salmon fishing business in Prince William Sound Alaska.

2002-2007 **University of Alaska at Anchorage**
Environmental Engineering Graduate Level Program, Adjunct Professor Air Pollution Control.

1999-2002 **State of Alaska, Department of Environmental Conservation**
Environmental Supervisory Position
Industry Preparedness and Pipeline Program Manager, Alaska Department of Environmental Conservation, Division of Spill Prevention and Response. Managed 30 staff in four remote offices. Main responsibility was to ensure all regulated facilities and vessels across Alaska submitted high quality Oil Discharge Prevention and Contingency Plans to prevent and respond to oil spills. Staff included field and drill inspectors, engineers, and scientists. Managed all required compliance and enforcement actions.

1996-1999 **Arco Alaska Inc.**
Engineering and Supervisory Positions held
Prudhoe Bay Waterflood and Enhanced Oil Recovery Engineering Supervisor. Main responsibility was to set the direction for a team of engineers to design, optimize and manage the production over 120,000 barrels of oil per day from approximately 400 wells and nine drill sites, from the largest oil field in North America. Responsible for six concurrently operating drilling and workover rigs.

Prudhoe Bay Satellite Exploration Engineering Supervisor for development of six new Satellites Oil Fields. Main responsibility was to set the direction for a multidisciplinary team of Engineers, Environmental Scientists, Facility Engineers, Business Analysts, Geoscientists, Land, Tax, Legal, and Accounting. Responsible for two appraisal drilling rigs.

Lead Engineer for Arco Western Operating Area Development Coordination Team. Lead a multi-disciplinary team of engineers and geoscientists, working on the Prudhoe Bay oil field.

1989-1996 **BP Exploration (Alaska), Inc.**
Environmental, Engineering, and Supervisory Positions held
Senior Engineer Environmental & Regulatory Affairs Department. Main responsibilities included: air quality engineering, technical and permitting support for Northstar, Badami, Milne Point Facilities and Exploration Projects.

Senior Engineer/Litigation Support Manager. Duties included managing a multidisciplinary litigation staff to support the ANS Gas Royalty Litigation, Quality Bank Litigation and Tax Litigation. Main function was to coordinate, plan and organize the flow of work amongst five contract attorneys, seven in-house attorneys, two technical consultants, eight expert witnesses, four in-house consultants and twenty-two staff members.

Senior Planning Engineer. Provided technical, economic, and negotiations support on Facility, Power, Water and Communication Sharing Agreements. Responsibilities also included providing technical assistance on recycled oil issues, ballast water disposal issues, chemical treatment options, and contamination issues.

Production Planning Engineer. Coordinated State approval of the Sag Delta North Participating Area and Oil Field. Resolved technical, legal, tax, owner and facility sharing issues. Developed an LPG feasibility study for the Endicott facility.

Reservoir Engineer. Developed, analyzed and recommended options to maximize recoverable oil reserves for the Endicott Oil Field through 3D subsurface reservoir models, which predicted fluid movements and optimal well placement for the drilling program. Other duties included on-site wellbore fluid sampling and subsequent lab analysis.

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

1987-1989 **Standard Oil Production Company, Production Engineer**
Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

Engineering Internship, Barry Waterflood Oklahoma City OK.

1986 **Conoco, Production Engineer**
Production Engineer. Engineering Internship, Hobbs New Mexico.

1985-1986 **New Mexico Institute of Mining and Technology**
Petroleum Research & Recovery Center
Laboratory Research Assistant, Enhanced Oil Recovery, Surfactant Research.

Harvey Consulting, LLC, Major Projects and Publications

Northeast Natural Energy, LLC. and Enrout Properties, LLC vs. The City of Morgantown, West Virginia, technical support to The City of Morgantown, 2011.

Arctic Oil and Gas Project, technical support to Pew Charitable Trust, 2010-2011.

Stockport Mountain Corporation, LLC vs. Norcross Wildlife Foundation, Inc., technical support to Norcross Wildlife Foundation, Inc., 2011.

Nikaitchuq Oil and Gas Development Project, technical review and advice to North Slope Borough, 2011.

Valdez Marine Terminal, Oil Spill Prevention Audit, report prepared for Prince William Sound Regional Citizens Advisory Council, 2011.

Great Bear Petroleum Exploration Oil Spill Prevention and Response Plan, technical review and comments prepared for North Slope Borough, 2011.

Recommendations to Improve the December 9, 2010 Delaware River Basin Commission (DRBC) Proposed Natural Gas Development Regulations, report prepared for Delaware Riverkeeper Network, 2011.

Oooguruk Oil and Gas Development Project, technical review and advice to North Slope Borough, 2011.

Trans-Alaska Pipeline Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for North Slope Borough, 2011

Shell Beaufort Sea Exploration Plan, technical support to North Slope Borough, 2007-2011.

Canadian National Energy Board, Offshore Drilling Review, technical support to WWF-Canada, 2011.

Shell Chukchi Sea Exploration Plan, technical support to North Slope Borough, 2010-2011.

SINTEF Behavior of Oil and Other Hazardous and Noxious Substances (HNS) spilled in Arctic Waters (BoHaSA) Report, technical review and advice to WWF, 2011.

Milne Point Oil & Gas Project, technical review and advice to North Slope Borough, 2011

National Commission Report on the BP Deepwater Horizon Oil Spill and Offshore Drilling, the Challenges of Oil Spill Response in the Arctic, technical analysis and recommendations prepared for Pew Charitable Trust, 2010.

Appeal of U.S. Forest Service Plan of Operations Denial for Wolcott Gold Mining Operation, technical report and appeal filing for Wolcott Gold Mining, 2010.

Valdez Marine Terminal Oil Spill Prevention and Response, technical support Prince William Sound Regional Citizens Advisory Council, 2002-2011.

Environmental Impacts and Regulation of Natural Gas Production, E2 Environmental Entrepreneurs, Presentation, 2011.

Petroleum and Natural Gas Systems, Subpart W, Mandatory Reporting of Greenhouse Gases, technical support to Natural Resources Defense Council and Sierra Club, 2010-2011.

Delaware River Basin Commission (DRBC) Consolidated Administrative Hearing on Grandfathered Exploration Wells, report prepared for Delaware Riverkeeper Network, 2010.

Recommendations for Australian Government Commission of Inquiry Montara Well Head Platform Uncontrolled Hydrocarbon Release, - Final Findings Document Post Commission of Inquiry Proceedings, report prepared for World Wide Fund for Nature Australia, 2010.

Gas Well Risk Management Controls, Protection of Groundwater Resources and Safe Well Construction, Operation and Abandonment, analysis prepared for Environmental Defense Fund and Sierra Club, 2010.

Recommendations for Pennsylvania's Proposed Changes to Oil and Gas Well Construction Regulations, report prepared for Earthjustice and Sierra Club, 2010

Ohio Senate Bill 165 Implementation Workgroup, revised Oil and Gas Standards for Ohio, Engineering Support to Environmental Defense Fund and Sierra Club, 2010.

New York State (NYS) Casing Regulation Recommendations, report prepared for Natural Resources Defense Council, 2009.

2011 Arctic Oil & Gas General NPDES Permit (Arctic GP) Heavy Metal Discharges (Mercury and Cadmium) in Drilling Muds and Cuttings, report to North Slope Borough, 2010.

Onshore Seismic Exploration Best Practices & Model Permit Requirements, report prepared for Natural Resources Defense Council, 2010.

Comparison of 2009 Timor Sea Well blowout to Gulf of Mexico Well blowout, report prepared for World Wide Fund for Nature Australia, 2010.

Recommendations for Profitable Greenhouse Gas Reductions from Oil and Gas Facilities in New Mexico, report to Natural Resources Defense Council, 2010.

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Curriculum Vitae

Objective: To provide diverse research and consulting services to nonprofit, government, legal and industry clients focusing on groundwater modeling, hydrogeology, environmental forensics and compliance, NEPA analysis, federal and state regulatory review, fluvial morphology and environmental and water policy.

Education

Years	Degree	University
1992-96	Ph.D. Hydrology/Hydrogeology	University of Nevada, Reno Dissertation: Stochastic Structure of Rangeland Streams
1990-92		University of Arizona, Tucson AZ Classes in pursuit of Ph.D. in Hydrology.
1988-90	M.S. Hydrology/Hydrogeology	University of Nevada, Reno Thesis: Stream Morphology, Stability and Habitat in Northern Nevada
1981-83		University of Colorado, Denver, CO Graduate level water resources engineering classes.
1977-81	B.S., Civil Engineering	University of Colorado, Boulder, CO

Special Coursework

Years	Course	Sponsor
2011	Hydraulic Fracturing of the Marcellus Shale	National Groundwater Association
2008	Fractured Rock Analysis	MidWest Geoscience
2005	Groundwater Sampling Field Course	Nielson Environmental Field School
2004	Environmental Forensics	National Groundwater Association
2004 and -5	Groundwater and Environmental Law	National Groundwater Association

Professional Experience

Years	Position	Duties
1993-Pr.	Hydrologic Consultant	Surface, groundwater and systems modeling, hydrogeology studies, stream restoration design, watershed modeling studies and expert testimony for industry, nonprofit groups, and government agencies.
1999-2004	Great Basin Mine Watch Executive Director	Responsible for reviewing and commenting on mining projects with a focus on groundwater and surface water resources, preparing appeals and litigation, writing reports about mining, fundraising, organizational development, supervision and personnel management.
1992-1997	University of Nevada, Reno Research Associate	Research on riparian area and watershed management including stream morphology, aquatic habitat, cattle grazing and low-flow and flood hydrology.
1990-1992	University of Arizona, Tucson Research and Teaching Assistant	Research on rainfall/runoff processes and climate models. Taught lab sections for sophomore level "Principles of Hydrology". Received 1992 Outstanding Graduate Teaching Assistant Award in the College of Engineering
1988-1990	University of Nevada, Reno Research Assistant	Research on aquatic habitat, stream morphology and livestock management.
1983-1988	US Bureau of Reclamation, Boulder City, NV Hydraulic Engineer	Performed hydrology planning studies on topics including floodplains, water supply, flood control, salt balance, irrigation efficiencies, sediment transport, stream morphology, flood frequency, rainfall-runoff modeling and groundwater balances.
1981-1983	Faulkner-Kellogg and Assoc., Lakewood Co Design Engineer	Basic drainage, grading and subdivision design. Flood control studies.

Representative Reports, Presentations and Projects

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Myers, T., 2007. Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Proposed Panels F and G. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV. December 11, 2007.

Myers, T., 2007. Hydrogeology, Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Documentation of a Groundwater Flow and Contaminant Transport Model. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV, December 7, 2007.

Myers, T., 2007. Review of Hydrogeology and Water Resources for the Final Environmental Impact Statement, Smoky Canyon Mine, Panels F and G and Supporting Documents. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno, NV. December 12, 2007.

Myers, T., 2007. Hydrogeology of the Powder River Basin of Southeast Montana Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council. February 12 2007.

Myers, T., 2007. Hydrogeology of the Santa Rita Rosemont Project Site, Conceptual Flow Model and Water Balance, Prepared for: Pima County Flood Control District, Tucson AZ

Myers, T., 2006. Review of Mine Dewatering on the Carlin Trend, Predictions and Reality. Prepared for Great Basin Mine Watch, Reno, NV

Myers, T., 2006. Hydrogeology of Spring Valley and Effects of Groundwater Development Proposed by the Southern Nevada Water Authority, White Pine and Lincoln County, Nevada. Prepared for Western Environmental Law Center for Water Rights Protest Hearing.

Myers, T., 2006. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs of the Pinnacle Gas Resource, Dietz Project In the Powder River Basin of Southeast Montana. Affidavit prepared for Northern Plains Resource Council, April 4 2006.

Myers, T., 2006. Review of Hydrogeology and Water Resources for the Draft Environmental Impact Statement, Smoky Canyon Mine, Panels F and G, Technical Report 2006-01-Smoky Canyon. Prepared for Natural Resources Defense Council.

Myers, T., 2006. Review of Nestle Waters North America Inc. Water Bottling Project Draft Environmental Impact Report / Environmental Assessment. Prepared for McCloud Watershed Council, McCloud CA.

Myers, T., 2005. Hydrology Report Regarding Potential Effects of Southern Nevada Water Authority's Proposed Change in the Point of Diversion of Water Rights from Tikapoo Valley South and Three Lakes Valley North to Three Lakes Valley South. Prepared for Western Environmental Law Center for Water Rights Protest Hearing

Myers, T., 2005. Review of Draft Supplemental Environmental Impact Statement, Ruby Hill Mine Expansion: East Archimedes Project NV063-EIS04-34, Technical Report 2005-05-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2005. Hydrogeology of the Powder River Basin of Southeast Montana, Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council, Billings, MT in support of pending litigation.

Myers, T., 2005. Nevada State Environmental Commission Appeal Hearing, Water Pollution Control Permit

Renewal NEV0087001, Big Springs Mine. Expert Report. Prepared for Great Basin Mine Watch, Reno NV.

Myers, T., 2005. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs In the Powder River Basin of Southeast Montana. Prepared for Northern Plains Resource Council, Billings, MT.

Myers, T., 2004. An Assessment of Contaminant Transport, Sunset Hills Subdivision and the Anaconda Yerington Copper Mine, Technical Report 2004-01-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Memorandum: Pipeline Infiltration Project Groundwater Contamination. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Report Seepage From Waste Rock Dump to Surface Water The Jerritt Canyon Mine, Technical Report 2004-03-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2001. An Assessment of Diversions and Water Rights: Smith and Mason Valleys, NV. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrogeology of the Basin Fill Aquifer in Mason Valley, Nevada: Effects of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrology and Water Balance, Smith Valley, NV: Impacts of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV

Myers, T., 2000. Alternative Modeling of the Gold Quarry Mine, Documentation of the Model, Comparison of Mitigation Scenarios, and Analysis of Assumptions. Prepared for Great Basin Mine Watch. Center for Science in Public Participation, Bozeman MT.

Myers, T., 2000. Environmental and Economic Impacts of Mining in Eureka County. Prepared for the Dept. Of Applied Statistics and Economics, University of Nevada, Reno.

Myers, T., 1999. Water Balance of Lake Powell, An Assessment of Groundwater Seepage and Evaporation. Prepared for the Glen Canyon Institute, Salt Lake City, UT.

Myers, T., 1998. Hydrogeology of the Humboldt River: Impacts of Open-pit Mine Dewatering and Pit Lake Formation. Prepared for Great Basin Mine Watch, Reno, NV.

Peer-Reviewed Publications

Myers, T., in review. Potential contaminant pathways from hydraulically fractured shale to aquifers. *Ground Water*.

Myers, T., 2009. Groundwater management and coal-bed methane development in the Powder River Basin of Montana. *J Hydrology* 368:178-193.

Myers, T.J. and S. Swanson, 1997. Variation of pool properties with stream type and ungulate damage in central Nevada, USA. *Journal of Hydrology* 201-62-81

Myers, T.J. and S. Swanson, 1997. Precision of channel width and pool area measurements. *Journal of the*

American Water Resources Association 33:647-659.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of pool-to-pool structure in small Nevada rangeland streams. *Water Resources Research* 33(4):877-889.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of transect-to-transect properties of Great Basin rangeland streams. *Water Resources Research* 33(4):853-864.

Myers, T.J. and S. Swanson, 1996. Long-term aquatic habitat restoration: Mahogany Creek, NV as a case study. *Water Resources Bulletin* 32:241-252

Myers, T.J. and S. Swanson, 1996. Temporal and geomorphic variations of stream stability and morphology: Mahogany Creek, NV. *Water Resources Bulletin* 32:253-265.

Myers, T.J. and S. Swanson, 1996. Stream morphologic impact of and recovery from major flooding in north-central Nevada. *Physical Geography* 17:431-445.

Myers, T.J. and S. Swanson, 1995. Impact of deferred rotation grazing on stream characteristics in Central Nevada: A case study. *North American Journal of Fisheries Management* 15:428-439.

Myers, T.J. and S. Swanson, 1992. Variation of stream stability with stream type and livestock bank damage in northern Nevada. *Water Resources Bulletin* 28:743-754.

Myers, T.J. and S. Swanson, 1992. Aquatic habitat condition index, stream type, and livestock bank damage in northern Nevada. *Water Resources Bulletin* 27:667-677.

Zonge, K.L., S. Swanson, and T. Myers, 1996. Drought year changes in streambank profiles on incised streams in the Sierra Nevada Mountains. *Geomorphology* 15:47-56.

Selected Abstracts, Magazine and Proceedings Articles

Myers, T., 2006. Modeling Coal Bed Methane Well Pumpage with a MODFLOW DRAIN Boundary. In MODFLOW and More 2006 Managing Ground Water Systems, Proceedings. International Groundwater Modeling Center, Golden CO. May 21-24, 2006.

Myers, T., 2006. Proceed Carefully: Much Remains Unknown, *Southwest Hydrology 5(3)*, May/June 2006, pages 14-16.

Myers, T., 2004. Monitoring Well Screening and the Determination of Groundwater Degradation, Annual Meeting of the Nevada Water Resources Association, Mesquite, NV. February 27-28, 2004.

Myers, T., 2001. Impacts of the conceptual model of mine dewatering pumpage on predicted fluxes and drawdown. In MODFLOW 2001 and Other Modeling Odysseys, Proceedings, Volume 1. September 11-14, 2001. International Ground Water Modeling Center, Golden, Colorado.

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Kendall, D.R. (ed.), Conjunctive Use of Water Resources: Aquifer Storage and Recovery. AWRA Symposium, Long Beach California. October 19-23, 1997

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Life in a Closed Basin, Nevada Water Resources Association, October 8-10, 1997, Elko, NV.

Myers, T., 1997. Uncertainties in the hydrologic modeling of pit lake refill. American Chemical Society Annual Meeting, Las Vegas, NV, Sept. 8-12, 1997.

Myers, T., 1997. Use of Groundwater modeling and geographic information systems in water marketing. In Warwick, J.J. (ed.), Water Resources Education, Training, and Practice: Opportunities for the Next Century. AWRA Symposium, Keystone, Colo. June 29-July 3, 1997.

Myers, T., 1995. Decreased surface water flows due to alluvial pumping in the Walker River valley. Annual Meeting of the Nevada Water Resources Association, Reno, NV, March 14-15, 1995.*

Select Testimony in Litigation and Administrative Hearings

Northeast Natural Energy LLC v. City of Morgantown, Monongalia Circuit Court, Civil Action No. 11-C-411. 2011. Submitted to Deposition. Case dismissed on constitutional grounds.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 53987-53992, 54003-54021. September 26 through November 14, 2011, Spring Valley, Cave Valley, Dry Lake and Delamar Valley. Testimony on behalf of protestants Great Basin Water Network, Confederated Tribes of the Goshute Reservation.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 53987-53992, Cave Valley, Dry Lake, and Delamar Valley, NV. February 4 through February 14, 2008. Testimony on behalf of protestant Great Basin Water Network.

Cole et al v. J.M.Huber Corp. and William DeLapp. U.S. District Court for the District of Wyoming. Case No. 06-CV-01421. Written evidence reports and deposition. Case settled.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s, 54003-54021, Spring Valley, NV. Testimony on behalf of protestant Great Basin Water Network. September 11-26, 2006.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s, 54003-54021, Spring Valley, NV. Testimony on behalf of protestant Great Basin Water Network. September 11-26, 2006.

Montana 22nd Judicial District Court, Big Horn County. Diamond Cross Properties, LLC, and Northern Plains Resource Council, and Tongue River Water Users Association v. State of Montana, Pinnacle Gas Resources. Civil Cause No. DV 05-70. Affidavit provided.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 72787 – 72797, Tickaboo/Three Lakes Basin. Testimony on behalf of Sierra Club, Indian Springs. November 28 – 30, 2005.

Earlier, several cases before the Nevada State Environmental Commission, on behalf of Great Basin Mine Watch.

CURRICULUM VITAE

MILLER, GLENN C.

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email: gcmiller@unr.edu

Born November 17, 1950

Education:

University of California, Santa Barbara, CA	B.S. Chemistry	1972
University of California, Davis, CA	Ph.D. Agricultural Chemistry	1977

Employment:

Univ. of Nevada, Reno	Aug-2009-present	Professor, and Director of the Graduate Program in Environmental Sciences
	2008-2009	On leave for 11 months serving as Manager, Environmental Exposure Assessment, Valent USA Corporation, Walnut Creek CA
	2007-2008, 2010-present	President UNR Nevada Faculty Alliance
	1995-2006	Director, Graduate Program in Environmental Sciences and Health
	1998-2004	Director, Center for Environmental Science and Engineering
	1989-	Professor
	1983-89	Associate Professor
	1979-83	Assistant Professor
	1978-79	Lecturer
Environmental Protection Agency	1977-78	Research Chemist

Professional Societies:

American Chemical Society, Agrochemicals Division and Environmental Division
American Association for the Advancement of Science
Society of Environmental Toxicology and Chemistry
Sigma Xi

Awards:

Thornton Peace Prize (1982)
Junior Faculty Research Award (1982)
UNR Foundation Professor (1991)
Conservationist of the Year, Nevada Wildlife Federation (1995)
College of Agriculture Researcher of the Year (1998)
Friend of the Lake Award, League to Save Lake Tahoe (2001)

Other Professional Activities

Environmental Protection Agency: Competitive Grants Review Panel 1985-1995
Environmental Protection Agency: Advisory Committee on Mining Waste 1991-1993
Environmental Protection Agency: Stakeholder Advisory Committee on Commodity Mercury 2007
Nevada Division of Environmental Protection: Technical Advisory Committee on the Carson River Superfund Site 1991-1994
American Chemical Society, Division of Environmental Chemistry: Chair of the Student Awards Committee 1988-1992
American Chemical Society, Division of Environmental Chemistry: Chair of the Awards Committee 1997-2002
UNR Environmental Studies Board: Chairman 1987-1991
UNR Environmental Science and Health Graduate Program: Director 1995-2006
Consultant to various public interest organizations, companies and law firms
Hydrology/Hydrogeology Graduate Faculty: Member 1989-present
Reviewer for numerous environmental chemistry journals
Co-owner and vice-president: Nevada Environmental Laboratories (Las Vegas and Reno) 1990-1999
Manager, Environmental Exposure Assessment, Valent USA Corporation 8/2008- 8/2009

Courses Taught

Humans and the Environment: Environment 100
Environmental Toxicology: NRES 432/632
Environmental Chemicals: Exposure, Transport and Fate: NRES 433/633
Analysis of Environmental Contaminants: NRES 430/630
Risk Assessment, NRES 793C
Global and Regional Issues in Environmental Science: NRES 467/667

Community and Conservation Service Activities

City of Reno, Charter Review Commission: Chairman 1990-93
Peavine Grade School PTA: Co-President 1990-1992
Sierra Club Mining Committee (national): Co-Chair 1989-1992
League to Save Lake Tahoe Board of Directors: 1986-1999
Mountain and Desert Research Fund: 1987-present
Dupont-Conoco Environmental Leadership Award in Mining Committee: 1989-1994
Nevada Interagency Reclamation Award Committee: 1990-1992
Washoe County School District Science Advisory Board: 1992-2000
Chairman, 1993-94
Earthwords: Board Member 1999-present
Tahoe Baikal Institute: Board Member 1998-present, Chair 2002-2003
Environmental Law Alliance Worldwide Board Member: 2000-present, Chair:2009
Great Basin Mine Watch: Board Member 1994-present, Chair 2001-2006
Center for Science in Public Participation: Board Member 1998-present
Great Basin Institute, Board Member 2000-present, Chair 2001-present
United Nations Environmental Program Committee for Development of a Code for Use of Cyanide in Mining: 2000-2002
Mining, Minerals and Sustainable Development, Assurance Group Committee Member, 2000-2002
National Research Council committee on Methyl Bromide: 1999-2001
National Research Council committee on Mining Technology: 2000-2002

National Research Council committee on USGS Mineral Resources Program, 2000-2003
US Environmental Protection Agency Committee on Management of Mercury Stores in the U.S. 2007

Research Interests: Remediation of mine waste contamination. Mining pit lake water quality. Fate and transport of organic compounds in soils and the atmosphere. Methods of remediation of gasoline contaminated soils; Photochemical transformation of organic contaminants on soil surfaces. Instrumental development of chromatographic systems.

Grants Received: (1982-present)

$ 14,550 "Atmospheric Photolysis of Pesticides," A Junior Faculty Research Award from the UNR Research Advisory Board, 1982.

$ 3,000 "Photolysis of CGA-41065," CIBA GEIGY Corporation, 1982.

$ 4,000 "Chemotaxonomy of Sagebrush Using High Performance Liquid Chromatography," Intermountain Research Station USDA, 1984.

$ 83,000 "Analysis of Bovine Tissue for Chlorinated Hydrocarbons," Environmental Protection Agency, 1984-85.

$ 18,300 "Photooxidation of Sulfide Containing Pesticides on Soil Surfaces," Western Regional Pesticide Impact Assessment Program, 1984.

$ 2,500 "Identification of Sagebrush Taxa Based on Liquid Chromatographic Analyses of Phenolics" Research Advisory Board, 1986.

$235,500 "Factors Affecting the Photolysis of Dioxins on Soil Surfaces," U.S. Environmental Protection Agency, 1986-89.

$ 15,160 "Vapor Phase Photolysis of Phorate," American Cyanamid Corporation, 1987.

$ 2,500 "Identification of Sagebrush Taxa Based on Liquid Chromatographic Analyses of Phenolics," UNR Research Advisory Board, 1987.

$ 48,792 "Upgrading Municipal Wastewater Effluents for Urban Water Reuse through Phytochemical Oxidations: System Development and Operational Criteria," U.S. Geological Survey, State Water Research Institute Program (Co-P.I. with Richard Watts), 1986-88.

$ 17,200 "Vapor Phase Photolysis of Malathion," American Cyanamid, 1988.

$ 16,460 "Aging Groundwater: A comparison of the Fluorocarbon Method to the Tritium Method," U.S. Geological Survey, State Water Research Institute Program (Co-P.I. with K. Sertic), 1988-89. (Competitive Grant, State of Nevada) Terminated 6-89.

$206,000 "In Situ Treatment of Organic Hazardous Wastes in Surface Soils Using Fenton's Reagent." U.S. Environmental Protection Agency (Co-P.I. with Richard Watts), 1988-89. (Competitive Grant, national)

$ 23,200 "Evaporation of Gasoline from Soils," Nevada Division of Environmental Protection Co-P.I. with Susan Donaldson), (Contract).

$ 50,000 "Photolysis of Pesticides on Soils," American Cyanamid Corporation (Unrestricted Grant, noncompetitive)

$ 15,600 "Vapor Phase Photolysis of Diazinon and Methyl Parathion" Western Region Pesticide Impact Assessment Program (USDA) (competitive) 1989-90

$ 30,000 "Interface for a Capillary electrophoresis Effluent and a Mass Spectrometer" Linear Corporation 1989-90. (Co P.I. with Murray Hackett) (contract)

$ 15,000 "UV-Gas Chromatographic Dectector" Linear Corporation 1990. (Co P.I. with Murray Hackett) (Noncompetitive grant)

$153,000 "Enhancement of Photodegradation of Pesticides in Soil by Transport Upward in Evaporating Water" (USGS Competitive) 1991-94

$ 50,000 "Pit Water from Precious Metal Mines" U.S. Environmental Protection Agency, 1992-94

$ 91,000 "Remediation of Acid Mine Drainage at Leviathon Mine" Lahontan Water Quality Control Board. (Contract, Co P.I. with Tom Wildman, Colorado School of Mines) 1992-94.

$159,000 " Ecological Toxicology of Metam Sodium and it Derivatives in the Terrestrial and Riparian Environments of the Sacramento River" California Fish and Game, 1992-1995 (G.C. Miller project, part of a larger project with George Taylor at the Desert Research Institute)

$43,092 “Atmospheric Transport and Deposition of Organophosphates and Other Pesticides as Input to Sierra Nevada Surface Waters” USDA-NRI. 1995-98. Co-P.I. with P.I. James N. Seiber. Task 2.

$80,427 “Linked Techniques for Contaminant Removal from Soil in Arid/Semiarid Environments” Dept. of Energy. 1993-96. Co.P.I with James N. Seiber.

$107,000 “Chemical Environmental Problems Associated with Mining” NIEHS 1993-96. Core B portion. This was a project of a larger Superfund Grant to UNR. James N. Seiber, P.I.

$36,900 “Protocol for Evaluation of Pesticide Photodegradation” Dow-Elanco. 1995-97. (Contract)

$45,000 “Photolysis of Pesticides” Dupont Chemical Company. 1995-98. Unrestricted gift to support ongoing research.

$275,000 “Remediation of Acid Mine Drainage at the Leviathan Mine”. Nevada Division of Environmental Protection. 1996-99

$5000 “Evaluation of Limnology and Water Quality of a Porphyry-Copper Pit Mine Lake” Public Resource Associates 1996.

$767,000 Geochemical, Biological and Economic Impacts of Arsenic and Related Oxyanions on a Mining-Impacted Watershed” NSF-EPA, 1997-01

$46,000 “Remediation of Acid Mine Drainage at the Leviathan Mine”. Lahontan Regional Water Quality Control Board, 2000-2001

$30,000 "Use of Sulfate-Reducing Bioreactors to Remove Zinc in Mine Drainage" Placer Dome Corporation. 2000-2001

$50,000 “Release of Gasoline Constituents from Marine Engines to Lake Tahoe” Lahontan Regional Water Quality Control Board, 1998-1999

$70,000 "Impact of Marine Engine Exhaust on Pyramid Lake" U.S. Environmental Protection Agency, in cooperation with the Pyramid Lake Paiute Tribe. 2000-2001.

$570,000 "An Environmental Assessment of the Impacts of Polycyclic Aromatic Hydrocarbons in Lake Tahoe and Donner Lake" California Regional Water Quality Control Board, Lahontan Region. 2001-2003.

$126,000 "Operation of a Bioreactor at the Leviathan Mine" Contract with ARCO, 2001-2002

$75,000 Trifluroacetic Acid in Antarctic Ice, National Science Foundation 2001-2004

$190,500 “Mercury Deposition Associated with Mining, U.S. Environmental Protection Agency, 2002-2004

$53,000 Passivation of Acid Generating Rock at the Golden Sunlight Mine, Placer Dome Corporation 2002-2003

$520,000 “Operation of a Bioreactor at the Leviathan Mine" Contract with ARCO, 2003-2007

$250,000 “Risk Assessment and Fate of Polyacrylamide and Acrylamide in Irrigation Canals and Receiving Water” A subcontract from the Desert Research Institute on a project from the U.S. Bureau of Reclamation. 2004-2008

$55,000 Passivation of Acid Generating Rock, Freeport McMoran, 2009-2010

$75,000 Biofuel crops on arid lands, Co-P.I. U.S. Department of Energy, 2010-2011

Publications:

G.C. Miller and D.G. Crosby, "Photodecomposition of Sustar^{R} in Water." J. Agric. Food Chem. 26:1316 (1978).

G.C. Miller and R.G. Zepp, "Effects of Suspended Sediments on Photolysis Rates of Dissolved Pollutants." Water Research 13:453 (1979).

G.C., Miller, M.J. Miille, D.G. Crosby, S. Sontum and R.G. Zepp, "Photosolvolysis of 3,4-Dichloroaniline in Water: Evidence for an Aryl Cation Intermediate." Tetrahedron 35:1797 (1979).

G.C. Miller and R.G. Zepp, "Photoreactivity of Pollutants Sorbed on Suspended Sediment." Environ. Sci. Technol. 13:860 (1979).

G.C. Miller, R. Zisook and R.G. Zepp, "Photolysis of 3,4-Dichloroaniline in Natural Waters." J. Agric. Food Chem. 28:1053 (1980).

G.C. Miller, R.G. Warren, K. Gohre and L. Hanks, "A Gas Chromatographic Method for Determining Strychnine Residues in Alfalfa." J. Assoc. Off. Anal. Chem. 65:901 (1982).

G.C. Miller and W.W. Miller, Eds. "Effect of Sewage on the Truckee River." A symposium published by the University of Nevada, College of Agriculture (1982).

G.C. Miller and R.G. Zepp, "Extrapolating Photolysis Rates from the Laboratory to the Environment." Residue Reviews 85:89 (1983).

G.C. Miller and D.G. Crosby, "Pesticide Photoproducts: Generation and Significance." J. Clin. Toxicol. 19:707 (1983).

G.C. Miller, W.W. Miller, J.W. Warren and L. Hanks, "Soil Sorption and Alfalfa Uptake of Strychnine Applied as an Agricultural Rodenticide." J. Environ. Quality 12:526 (1983).

G.C. Miller and D.G. Crosby, "Photooxidation of 4-Chloroaniline and N-(4-Chlorophenyl)-Benzene-sulfonamide to Nitroso- and Nitro-Products." Chemosphere 12:1217-1227 (1983).

K. Gohre and G.C. Miller, "Singlet Oxygen Generation on Soil Surfaces." J. Agri. and Food Chem. 31:1104-1108 (1983).

R.G. Zepp, P.F. Schlotzhauer, M.S. Simmons, G.C. Miller, G.L. Baughman and N.L. Wolfe, "Dynamics of Pollutant Photoreactions in the Hydrosphere." J. of Fresenius Z. Anal. Chem. 319:119-125 (1984).

K. Gohre and G.C. Miller, "Photochemical Generation of Singlet Oxygen on Non-transition Metal Surfaces." J. Chem. Soc. Faraday Trans. I 81:793-800 (1985).

R.V. Tamma, G.C. Miller and R. Everett, "High-Performance Liquid Chromatographic Analysis of Coumarins and Flavonoids from Section Tridentatae of ***Artemisia***." J. Chromatography 322:236-239 (1985).

K. Gohre, R. Scholl and G.C. Miller, "Singlet Oxygen Reactions on Soil Surfaces." Environ. Sci. Technol. 20:934-938 (1986).

K. Gohre and G.C. Miller, "Photooxidation of Thioether Pesticides on Soil Surfaces." J. Agric. Food Chem. 34:709-713 (1986).

B.R. Smith, G.C. Miller, R.W. Mead and R.E.L. Taylor, "Biosynthesis of Asparagine and Taurine in the Freshwater Prawn, ***Macrobrachium rosenbergii*** (De Man)." Comp. Biochem. Physiol. 87B(4):827-831 (1987).

B.R. Smith, G.C. Miller and R.W. Mead, "Taurine Tissue Concentrations and Salinity Effect on Taurine in the Freshwater Prawn ***Macrobrachium rosenbergii*** (De Man)." Comp. Biochem. Physiol. 87A(4):907-909 (1987).

G.C. Miller and V. Hebert, "Environmental Photodecomposition of Pesticides." In: University of California publication - Fate of Pesticides in the Environment (J.W. Biggar and J.N. Seiber, eds.) Chapt. 8, p. 75-86 (1987).

G.C. Miller and R.G. Zepp, "2,3,7,8-Tetrachlorodibenzo-p-dioxin: Environmental Chemistry." In: Solving Hazardous Wastes Problems: Learning from Dioxins (J.H. Exner, ed.) American Chemical Society Symposium Series 338, Chapter 6, pp. 82-93 (1987).

C.R. Blincoe, V.R. Bohman, G.C. Miller, R.L. Scholl, W.W. Sutton and L.R. Williams, "Excretion and Tissue Concentration of Pentachlorophenol Following Controlled Administration to Cattle." J. Animal Sci. 65 Supplement #1 (1987).

G.C. Miller, V.R. Hebert and R.G. Zepp, "Chemistry and Photochemistry of Low-Volatility Organic Chemicals on Environmental Surfaces." Env. Sci. Tech. 21:1164-1167 (1987).

V.R. Bohman, C.R. Blincoe, G.C. Miller, R.L. Scholl, W.W. Sutton and L.R. Williams, "Biological Monitoring Systems for Hazardous Waste Sites." EPA Final Report #CR 809 787 (1988).

F.M. Wilt, G.C. Miller and R.L. Everett, "Monoterpene Concentrations of Litter and Soil of Singleleaf Pinyon Woodlands of the Western Great Basin." Great Basin Naturalist 48:228-231 (1988).

K. Mongar and G.C. Miller, "Vapor Phase Photolysis of Trifluralin in an Outdoor Chamber." Chemosphere 17(11):2183-2188 (1988).

G.C. Miller, V.R. Hebert and W.W. Miller, "Effects of Sunlight on Organic Contaminants at the Atmosphere - Soil Interface." In: Reactions and Movement of Organic Chemicals in Soils (B. Sawhney, ed.) SSSA Special Publication No. 22, pp. 99-110 (1989).

G.C. Miller, V.R. Hebert, M.J. Miille, R. Mitzel and R.G. Zepp, "Photolysis of Octachlorodibenzo-p-Dioxin on Soils: Production of 2,3,7,8-TCDD." Chemosphere 18(1-6):1265-1274 (1989).

G.C. Miller, "Choosing an Analytical Lab" Nevada Waste Reporter Spring, 1989. (Publication of the Nevada Small Business Development Center).

N.L. Wolfe, U. Mingelgrin and G.C. Miller, "Abiotic Transformation Processes in Water, Sediments and Soils." In: B. Spencer and H.H. Cheng, eds., Pesticides and Other Toxic Organics in Soils, Soil Science Society of America, pp. 103-168 (1990).

S. Donaldson, G.C. Miller and W.W. Miller, "Extraction of Gasoline Constituents from Soil." J. Assn. Off. Anal. Chem. *73:*306-311 (1990)

V.R. Hebert and G.C. Miller, "Depth Dependence of Direct and Indirect Photolysis on Soil Surfaces." J. Agric. Food Chem. 38:913-918, (1990)

J.M. Basey, S.H. Jenkins and G.C. Miller, "Food Selection by Beavers in Relation to Inducible Defenses of Quaking Aspens" Oikos 59:57-62 (1990).

S. Donaldson, G. C. Miller, and W.W. Miller, "Volatilization of Gasoline Constituents from Soil. In: Proceedings of the Fourth National Outdoor Action Conference on Aquifer Restoration, Ground Water Monitoring and Geophysical Methods, Las Vegas NV May, 1990.

G.C. Miller, "Nevada's Environmental Commission: Changes Needed for the 1990's" in F. Ballister, Ed. The Nevada Environmental Commission, Published by Claremont College 1991.

S. Kieatiwong, L.V. Nguyen, V.R. Hebert, M. Hackett, G.C. Miller, M.J. Miille and R. Mitzel, "Photolysis of Chlorinated Dioxins in Organic Solvents and on Soils." Env. Sci. Techol. 24:1575-1580, (1990).

M. O. Theisen, G.C. Miller, C. Cripps, M. de Renobales and G.J. Blomquist, "Correlation of Carbaryl Uptake with Hydrocarbon Transport to the Cuticular Surface in the Cabbage Looper, Trichlplusia Ni. Pesticide Biochemistry and Physiology 40:111-116 (1991).

C. Thomas, R.S. MacGill, G.C. Miller, R.S. Pardini, "Photoactivation of Hypericin Generates Singlet Oxygen in Mitochondria and Inhibits Succinoxidase" Photochemistry and Photobiology, 55:47-53, (1991).

G.C. Miller, “Bringing Back the Land: Reclaiming Mining Disturbances” International Mine Waste Management, 1:1-5 (1991)

F. M. Wilt and G.C. Miller, "Seasonal variation of coumarin and flavonoid concentrations in persistent leaves of wyoming big sagebrush (Artemisia tridentata ssp. wyomingensis: Asteraceae) Biochemical Systematics and Ecology, 20:53-67 (1992)

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S.G. Donaldson, G.C. Miller and W.W. Miller, "Remediation of Gasoline-Contaminated Soil by Passive volatilization" Journal of Environmental Quality, 21:94-102, (1992)

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Ralph L. Seiler

PROFESSIONAL EXPERIENCE

Hydrologist

1979-2010 (retired) U.S. Geological Survey Carson City, NV

- Principal investigator for numerous water-quality investigations of surface water and groundwater, including identifying sources of phosphorus in the Carson River, sources of nitrate and bacteria in groundwater, and sources and distribution of TCE in groundwater near a landfill on an Air Force Base in Utah.
- Principal investigator for USGS Fallon leukemia investigation of ground-water quality which involved working closely with CDC, ATSDR, and the State of Nevada. Participated in many public meetings with State and Federal Agencies to explain results of findings related to the presence of arsenic, tungsten, uranium, and polonium-210 in Fallon area groundwater.
- Author of journal articles describing geochemical processes that result in exposure of the public to toxic trace elements and radionuclides.

PUBLICATIONS

Seiler and Wiemels, *in review at Environmental Health Perspectives*. Occurrence of ^{210}Po and biological effects of low-level exposure: The need for research.

Seiler, 2011a, Physical setting and natural sources of exposure to carcinogenic trace elements and radionuclides in Lahontan Valley, Nevada. Chemical-Biological Interactions [Epub ahead of print DOI:10.1016/j.cbi.2011.04.004]

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EDUCATION

Ph.D. Environmental Chemistry

1996-1999 University of Nevada, Reno Reno, NV

B.S./M.S. Biology

1969-1975 University of Utah Salt Lake City, UT

Michele C. Adams, P.E.
LEED AP
Principal Water Resources Engineer

Meliora Environmental Design, LLC

Relevant Experience

Ms. Adams is a Principal Engineer and founder of Meliora Environmental Design. For more than 25 years, her work has encompassed environmentally sensitive site design and sustainable water resources engineering. Building on a multi-disciplinary approach, her work includes both master planning and design for campuses, urban restoration projects, commercial, industrial and residential installations, public facilities, and environmental education centers. In all her work, Ms. Adams seeks to combine sound engineering science with an understanding of natural systems. She is a frequent lecturer and educator on the topics of water and sustainability, and has provided technical expertise to clients ranging from watershed advocacy organizations to corporations. Ms. Adams was one of the principle authors of the Pennsylvania Stormwater Manual, and serves on the U.S. Green Building Council's Technical Advisory Group for Sustainable Sites. She frequently serves as an expert witness with regards to stormwater and water quality issues. Current design projects in which Ms. Adams is engaged include the following:

Stormwater Management for Green and Public Properties, City of Philadelphia: Led a team of engineers, landscape architects, and planners in developing stormwater designs for the City of Philadelphia public properties. The stormwater and landscape designs are intended to reduce impacts to the City's combined sewer system, provide economic cost savings, and promote green infrastructure. Projects have included parks, schools, recreation facilities, and "green streets". A number of projects have been documented through construction and are being (or have been) built.

Purdue University Stormwater Plan: Development of a Stormwater Plan for retrofitting an urban campus to implement an LID approach and incorporate green infrastructure to improve water quality and reduce stormwater runoff volumes. Protection and recharge of drinking water source (groundwater) and water quality protection is a key component of recommendations.

Purdue University Site and Stormwater Improvements at the Mackey Football Fields and Ross-Ade Stadium Parking Lot, West Lafayette, IN: Design of nearly 3 acres of infiltration beds located beneath the Purdue Boilmaker's football practice fields to manage stormwater for the upper campus athletic complex. At the Ross-Ade Stadium, design of bioretention systems to pre-treat runoff from the parking lot and bordering roadways, a drainage area of nearly 6 acres, before the system connects to the infiltration beds under the adjacent football practice fields.

Stroud Water Research Center Environmental Education Center, Academy of Natural Sciences, Avondale, PA: For one of the nation's premier water research and education facilities, provided sustainable site design engineering related to stormwater management including rain gardens, water reuse, and green roof.

U.S. Botanic Garden Bartholdi Park, Washington, D.C.: Designing stormwater management measures in the landscape to serve as demonstration sites as well as to demonstrate compliance with the new Federal Regulations for stormwater management as part of Section 438 of the Energy Independence and Security Act. The project is also seeking certification from the Sustainable Sites Initiative.

High Performance Landscapes, New York City Parks and Recreation: Ms. Adams served as one of four authors in development of the New York City's *High Performance Landscapes* document, specifically addressing water issues. This publication will be the third in the series that began with *High Performance Buildings*.

Special Qualifications

Twenty-five years of experience in civil and water resources engineering.

Sustainable site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, tree trenches, vegetated roofs, etc) and alternative wastewater treatment systems (wetlands, drip irrigation, recirculating filters). Design for projects seeking LEED certification.

Watershed studies, computer modeling, stormwater sampling, stream flow monitoring, NPDES permit applications, mixing zone analyses, pollution prevention plans.

Professional Credentials

Bachelor of Science Civil Engineering
Pennsylvania State University, State College, PA, 1984

Graduate Coursework Water Resource Engineering
Villanova University, PA 1997-2001

Registered Professional Engineer in Delaware, Pennsylvania, Virginia, Maryland

LEED Accredited Professional

Waterview Recreation Center, City of Philadelphia and Pennsylvania Horticultural Society: For an existing urban recreation center, design of "green infrastructure" stormwater elements to improve community amenities and reduce combined sewer overflows. Elements include stormwater tree trenches, stormwater planter boxes, and a cistern for the community garden. *This project has recently been the subject of a GreenTreks video on stormwater.*

Greenstreets Design, East Falls: Led a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a "complete" street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. The goal was to develop a complete street that addressed stormwater, various transportation modes, and neighborhood greening and revitalization.

University of Pennsylvania Shoemaker Green, Philadelphia: Design of a passive open space on Penn's Campus that captures runoff generated by new and existing impervious surfaces into site and landscape features throughout the site. The project is also seeking certification from the Sustainable Sites Initiative.

Three Groves Ecovillage: Evaluating the Zoning Overlay for the proposed Ecovillage as well as designing the Water system, Wastewater Collection system, and stormwater measures for the site. Consisting of small residential buildings, community greenhouses, community buildings, natural pools, a constructed wetland treatment system, and bioswales, the proposed Ecovillage development is a model sustainable "green" neighborhood.

Philadelphia Zoo Master Plan: Development of water and environmental recommendations for the Zoo Master Plan, with focus on stormwater measures integrated into the Zoo's landscape to address flooding problems while promoting sustainability.

Greening and Stormwater Retrofits for Urban Schoolyards, Philadelphia: For two existing urbanized school yards (Greenfield School and Independence Charter School) that previously consisted only of asphalt, designed elements intended to both capture the first inch of runoff and provide greening, environmental education, and reduce heat island effects. Components include rain gardens, porous asphalt, porous pavers, and vegetated swales. *Greenfield School has recently been the subject of a GreenTreks video on stormwater.*

Stormwater Plans and Environmental Site Design Analysis for Maryland Projects: For the Chesapeake Bay Foundation and Audubon Society, Ms. Adams led an effort to evaluate various project sites in Maryland and provide recommendations and cost estimates for implementing landscape and stormwater measures to achieve the goals of Maryland's ESD process.

Okehocking Nature Center, Willistown Township, PA: Sustainable site design engineering for new Environmental Education Center, including stormwater management and wastewater treatment systems that are integrated with the natural landscape restoration.

Levin Tract Wooded Wetland Park, Radnor, PA: For the urbanized Radnor, PA area, developed a restoration concept design to convert an abandoned vacant parcel into a wooded wetland park area that will improve water quality from a 40-acre urban drainage area by creating a series of low, wooded wetland depressions and planting areas.

Professional Employment History

2007- Present
Principal Engineer and Founder
Meliora Environmental Design
Kimberton, PA

1997- 2007
Principal Engineer
Cahill Associates, West Chester, PA

1991-1997
Project Manager
Roy F. Weston, Inc., West Chester, PA

1984-1991
Project Engineer
Cahill Associates, West Chester, PA

Professional Memberships

U.S. Green Building Council – Sustainable Sites Technical Advisory Committee (SS TAG)

Member, American Society of Civil Engineers, Environmental Water Resources Institute

Member, Pennsylvania Association of Environmental Professionals

Member, American Water Resources Association

Visiting Guest Lecturer; University of Pennsylvania Schools of Architecture and Landscape Architecture; Philadelphia University, and Temple University

East Vincent Planning Commission Chairman

Ralston House, University of Pennsylvania: Design of stormwater elements to support an urban landscape restoration at an existing healthcare facility for the elderly.

Tyler Arboretum Path System: Designed a system of porous asphalt paths through an existing arboretum to improve access and address localized erosion problems.

Hershey Gardens Stormwater Plan: Developed program of rain gardens, wetlands, and restoration measures to address existing erosion and flooding problems.

North 3rd Street Corridor Sustainable Affordable Housing Plan, Philadelphia: With SMP Architects, designing guidelines for sustainable affordable housing, including stormwater measures to reduce combined sewer overflows and meet new City of Philadelphia ordinances.

Hamilton Children's Zoo at the Philadelphia Zoo: Design of site elements, including stormwater elements that provide educational opportunities, such as wetlands, green roofs, porous paths, and cisterns.

Oxford Library: Sustainable site design and engineering for a library addition to an urban library that includes porous pavers, rain gardens, and public outdoor gathering spaces to promote environmental education.

Mount Saint Joseph Academy Stormwater Improvements: With the Pennsylvania Horticultural Society, design of landscape-based restoration measures to improve stormwater management and educational opportunities at an existing school.

Chanticleer Garden: Stream daylighting of buried tributary and floodplain restoration.

Fire Engine 38: Site design of a new Fire Station in Philadelphia to include green roof, bioretention, and landscape restoration. Project will be LEED certified.

John Hopkins Sustainability House: Site design of a building at John Hopkins to create a Sustainability House and define sustainability criteria for University.

Stroud Model My Watershed: Providing technical expertise in the development of an educational watershed modeling tool being developed through funding from the National Science Foundation. Tool will allow interactive evaluation of development impacts on water balance and water quality, and allow alternative designs to be evaluated for benefits of groundwater restoration, stream health, and water quality.

Panther Hollow Watershed Restoration: Developing a watershed restoration plan which includes hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of two pilot projects to include elements such as an infiltration trench to capture adjacent street runoff, and retentive grading/infiltration berms to manage compacted lawn on a golf course.



For ten years prior to forming Meliora (1997 – 2007), Ms. Adams was a Principal Engineer with Cahill Associates, where she successfully directed and participated in all aspects of a number of projects.

Pennsylvania Stormwater Best Management Practices Manual, Pennsylvania DEP, co-author of State Manual describing structural and non-structural BMPs, Control Guidelines, calculation methodologies, and specifications, including a volume-based approach to stormwater.

Environmental and Stormwater Master Plan, UNC Chapel Hill, NC, Environmental master planning for sustainable stormwater approach to address large university expansion plan. Detailed hydrologic computer modeling performed in US EPA SWMM to evaluate existing infrastructure and recommend stormwater measures. Represented new LID approach in stormwater for UNC and was recognized by Sierra Club as a "Top Ten Building Better II" project.

Grey Towers National Monument, National Forest Service, Sustainable site design, including various stormwater measures for historic gardens, porous pavement, water and wastewater systems.

Washington National Cathedral, D.C., Restorative stormwater measures for Cathedral site and woods, including various infiltration measures (at source of runoff), infiltration for road system, channel stabilization, etc. Second phase included infiltration trenches integrated in to new outdoor amphitheater.

Mill Creek Community Garden and Clark Park Urban Stormwater Projects, Philadelphia, PA, Design of urban stormwater systems that collect runoff from City streets and infiltrate/manage water in urban green spaces such as community gardens and new basketball courts.

Cusano Center at John Heinz National Wildlife Refuge, Tinicum, PA, Sustainable site design for educational center, including various stormwater elements.

Springbrook Low Impact Development, Lebonon County, PA, Design of full LID stormwater system for 247 residential units in karst area, including over 120 individual stormwater systems (vegetated infiltration beds, infiltration trenches, rain gardens, porous pavements, etc.).

Bartrams Garden Master Plan, Philadelphia, PA, Restorative stormwater management recommendations for Master Plan of historic garden.

Regent Square Gateway, Nine Mile Run, Pittsburgh, PA, Concept and schematic design for urban stream and park "gateway".

Ford Rouge Stormwater Management, Dearborn, MI, Stormwater planning and design for major industrial facility re-development (Porous pavement, bioretention swales, vegetated systems).

Woodlawn Library, Wilmington, DE, Design of urban stormwater measures at new public library to reduce stormwater in combined sewers. Porous parking, bioretention, cisterns with re-use, stormwater planter boxes.

From 1991 through 1997, Ms. Adams was a Project Engineer and Project Manager at Weston.
Stormwater Management Programs and NPDES permitting Between 1992 and 1996, Ms. Adams developed and implemented stormwater management and sampling programs at over fifty industrial, commercial, and military facilities throughout the United States, including the Bureau of Engraving and Printing, Philadelphia International Airport, and various industrial facilities. These programs focused on reducing stormwater and water quality impacts from existing facilities.

Hydrologic, Hydraulic, and Mixing-Zone Modeling For a variety of watershed studies including Act 167 Plans, Ms. Adams conducted hydrologic and hydraulic modeling using various mathematical computer models, including USDA TR-20, EPA SWMM, and COE HEC models. Ms. Adams also performed floodway

Expert Testimony within Past Three Years

2010 **Blue Mountain Preservation Association vs Alpine Development Rose Resorts;** Pennsylvania Environmental Hearing Board. Expert witness on behalf of BMPA on issues related to stormwater management and water quality.

2010 **Koziell and Perrini vs Madison Township; Lackawanna Court of Common Pleas;** Expert witness on adverse stormwater impacts of road improvements.

June 2010 **West Vincent Zoning Hearing Board; Flather Property;** Testimony on behalf of Green Valleys Association and PennFuture related to impacts of **water** quality on variance request for stream buffer and wetland setback requirements.

Jan 2010 **West Pikeland Zoning Hearing Board;** Testimony on behalf of Green Valley Association related to impacts of water quality and stream health on variance requests to environmental ordinances.

2009/2010 **Tim and Jamie Lake vs The Hankin Group;** Court of Common Pleas Chester County; Expert witness on stormwater design and flooding.

2008-2009 **Crum Creek Neighbors vs DEP, et al;** Pennsylvania Environmental hearing Board; Expert witness on stormwater design review and impacts on flooding and water quality.

2007-2008 **Glenhardie Condominium vs. Realen Associates; Appeal of NPDES Post-construction Stormwater Management Permit;** Expert witness on behalf of Glenhardie related to stormwater design and flooding. Permit was withdrawn.

Expert Analysis and Comment within Past Three Years

2009/2010 **Pennsylvania Turnpike Expansion Project;** on behalf on National Park Service Valley Forge National Park and Valley Creek Coalition. Expert services related to review and comment of stormwater design and impacts on water quality and stream conditions.

2009/2010 **City of Philadelphia Longterm Control Plan;** on behalf of Natural Resources Defense Council and PennFuture; review of technical reports, policy documents, and draft permit conditions on issues related to stormwater management, water quality, stream health, and compliance with Clean Water Act and EPA Longtern Control Policy.

2010 **City of Chattanooga MS4 Permit**: For City of Chattanooga, providing technical guidance for incorporation of stormwater measures to address and restore impaired streams and meet TMDL requirements. Training sessions for municipal officials and program development.

Publications

Design for Flooding: Architecture, Landscape, and Urban Design for Resilience to Climate Change; By Donald Watson and Michele Adams; Wiley Publishing, Hardcover Nov 2010.

Park Design for the 21st Century: High Performance Landscape Guidelines; New York City Parks Department and NYC Design Trust; Nov 2010.

Porous Asphalt Pavement: 20 Years and Still Working, Michele Adams, Published in Stormwater Magazine May/Jun 2003

Presentations and Conference Proceedings

2010

Nov Greenbuild USGBC National Conference; New Directions in Stormwater Management and LEED
Nov AWRA National Conference; New Direction in Water Management
Oct Delaware Valley Green Building Council; New Directions in Stormwater Management in Philadelphia
Sep Pittsburgh Parks Conservancy; Michele Adams; "What's Going on in Panther Hollow" and examples of innovative engineering solutions to stormwater impacts on the watershed; Pittsburgh, PA
May "Sustainable Stormwater Management for Municipal Officials"; Lecture series for municipal officials sponsored by Brandywine Valley Association
Apr "Stormwater Management in Pennsylvania", Environmental Law Forum, Harrisburg, PA
Apr "Rainwater Management", Institute for Conservation Leadership
Mar "How to Challenge a Stormwater Permit and Win: A Look at the Crum Creek Neighbors Decision" Michele Adams, James Schmid, and John Wilmer; Schuylkill Watershed Congress; Pottstown, PA

2009

Dec "Bio-retention, Vegetative roofs, rain gardens, stormwater management" sponsored by East Nantmeal Township Environmental Council
Oct "Regenerative Urban Stormwater: Example Projects in the Philadelphia Region" Michele Adams and Susan McDaniels Pennsylvania Stormwater Conference; Villanova, PA
Oct Housing and Water: Syncing Neighborhood Development, Stormwater Management, and Water; AIA Design on the Delaware
Oct "Sustainability and Stormwater Management: Green Infrastructure" American Planning Association National Conference
Sept LID and Stormwater; 16th Annual Erosion Control Conference
May "Green Infrastructure and Urban Revitalization" Greening the Heartland Conference, Detroit, MI
May "Protecting Our Natural Resources: Design Leadership for the Next 100 Years" AIA National Conference, San Francisco.
May "Putting It Into Practice: Low Impact Development And Stormwater Management Training" Pennsylvania Land Conservation Conference
May "Reconnecting Water, Soils, and Vegetation: Stormwater Management in the Built Environment" ASLA PA/DE Annual Meeting.
Mar "Water, Soils, and Vegetation: Sustainable Site Design" Purdue University Sustainability Conference
Mar "Promoting LID Redevelopment in the Anacostia Watershed" Washington, DC

2008

Jan AIA/DVGBC, Philadelphia; Porous Pavement: How, Why, and When
Mar DVGBC Best of GreenBuild

2007

Nov USGBC GreenBuild, Chicago; Michele Adams; UNC Chapel Hill: A Campus-wide approach for Growth and Sustainability

Aug "Urban Stormwater and LEED"; Michele Adams, Energy Coordinating Agency of Phila; Demystifying LEED for Homes Event.

May "Low Impact Development: What's Important and What Should be Monitored"; Michele Adams and Wesley Horner; Tampa; 9th Conference on Stormwater Research & Watershed Management; Fla DEP

May "Low Impact Development"; Wesley Horner and Michele Adams; ASCE EWRI World Environmental &Water Resources Congress; Conference; Orlando, Fla

April "Integrating Sustainable Stormwater into the Campus"; Michele Adams and Thomas Cahill; Baltimore, MD; Smart and Sustainable Campuses Conference, EPA/Society for College and University Planning.

April; "Stormwater Management at UNC Chapel Hill: A Plan for Growth and Sustainability"; Jill Coleman, UNC, and Michele Adams; Wilmington, NC, 2nd National Low Impact Development Conference

April "Using the BMP Manual to Meet NPDES Requirements"; Michele Adams; State College, PA; Chesapeake Bay Foundation Confluence 2007, Connecting Communities to Creeks.

March "Porous Pavements"; Michele Adams, Public information session hosted by the City of Wichita

2006

Nov "Urban Stormwater BMPs: Finding Space for Stormwater in the Urban Environment", Michele Adams; Baltimore, MD; AWRA 2006 Annual Water Resources Conference

Nov "Sustainable Site Design"; Michele Adams; Philadelphia, PA; Design on The Delaware AIA Regional Conference

Sept "Stormwater Site Design: porous Asphalt and Other Innovative Stormwater Techniques"; Michele Adams; Kansas City, MI; American Public Works International Congress and Exposition

Sept "Sustainable Stormwater Management"; Michele Adams; Pittsburgh, PA; 3 Rivers Wet Weather 8th Annual Sewer Conference

Sept "Regent Square Gateway Vision for Nine Mile Run"; Marijke Hecht and Michele Adams; University of Pittsburgh, PA

Sept "The Etowah Habitat Conservation Plan and Runoff Limits"; Michele Adams; Atlanta, GA; Public workshops sponsored by Etowah Watershed Organization and the River Basin Center Institute of Ecology University of Georgia.

June Blair County LID Workshop; Michele Adams; Hollidaysburg, PA;

June Penn State Visitor Center LID Design; Michele Adams; State Colege, PA; Penn State Computational Methods in Stormwater Management

May "Rams Head Extensive Green Roof Design at UNC Chapel Hill"; Andrew Potts and Michele Adams; Boston, MA; Green Roofs for Healthy Cities Conference

May Penn State Visitor Center LID Demonstration Tour; Michele Adams; Pennsylvania Association of Environmental Professionals.

Mar "Porous Asphalt Pavement: The Right Choice"; Michele Adams; Orlando, FLA; NAPA World of Asphalt

Jan "Sustainable Stormwater Management"; Michele Adams; Atlantic City, NJ; NJ ASLA Annual Meeting Various Dates and Locations in PA: Stormwater Management Workshops for Municipal Officials and Engineers; Sponsored by the Pennsylvania Environmental Council

2005

Dec "Sustainable Design in Our Communities"; Michele Adams and Tavis Dockwiller; Sturbridge, MA; presented by Green Valleys Institute

Nov "Designing Bio/Infiltration Best Management Practices for Stormwater Quality Improvement"; Michele Adams; Madison, WI; University of Wisconsin Professional Development Course

Oct "Springbrook: Residential LID in a Limestone Area; Andrew Potts and Michele Adams; Villanova, PA; 2005 Pennsylvania Stormwater Management Symposium

July "Sustainable Site Design"; Michele Adams; Trenton, NJ; AIA NJ Tectonics of Sustainable Design

June Penn State Visitor Center LID Design; Michele Adams; State Colege, PA; Penn State Computational Methods in Stormwater Management

April "Urban Stormwater BMPs: Finding Space for Stormwater in the Urban Environment"; Wesley Horner and Michele Adams; Tampa, FLA; 8th Biennial Conf on Stormwater Research & Management.

Mar "Sustainable Site Design"; Michele Adams and Tavis Dockwiller; sponsored by Fulton County, PA

Ruth Ayn Sitler, P.E.
Water Resources Engineer

Meliora Environmental Design, LLC

Relevant Experience

Ms. Sitler is a Water Resources Engineer at Meliora Environmental Design with over seven years of civil engineering experience that includes low impact development and sustainable stormwater management design. To date, her experience has provided her with a vast multi-disciplinary background from which to draw for innovative design projects of all scopes and sizes, and includes commercial and residential construction, educational facility construction, stream restoration projects, abandoned mine reclamation, and pavement management and design. Ms. Sitler also has experience in environmental permitting as well as local government operations.

Current designs in which Ms. Sitler has been engaged include the following:

Greenstreets Design, East Falls: Part of a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a "complete" street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. The goal was to develop a complete street that addressed stormwater, various transportation modes, and neighborhood greening and revitalization.

Three Groves Ecovillage: Evaluating the Zoning Overlay for the proposed Ecovillage as well as designing the Water system, Wastewater Collection system, and stormwater measures for the site. Consisting of small residential buildings, community greenhouses, community buildings, natural pools, a constructed wetland treatment system, and bioswales, the proposed Ecovillage development is a model sustainable "green" neighborhood.

Panther Hollow Watershed Restoration: Developing a watershed restoration plan which includes hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of two pilot projects to include elements such as an infiltration trench to capture adjacent street runoff, and retentive grading/infiltration berms to manage compacted lawn on a golf course.

Philadelphia Zoo Master Plan: Development of water and environmental recommendations for the Zoo Master Plan, with focus on stormwater measures integrated into the Zoo's landscape to address flooding problems while promoting sustainability.

Special Qualifications

Seven years of experience in civil and water resources engineering.

Sustainable civil/site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, etc).

Integrated water resource planning; regional watershed planning; computer modeling; environmental , transportation, and construction permitting; local ordinance development and implementation.

Professional Credentials

Post-Graduate Coursework
Coastal Engineering
Old Dominion University, VA
2012-present

Master of Engineering
Environmental Engineering
Pennsylvania State University, PA, 2007

Bachelor of Science
Civil Engineering Technology
Pennsylvania College of Technology, PA 2004

Registered Professional Engineer in Pennsylvania

Certified Surveyor-in-Training in Pennsylvania

Professional Employment History

2011- Present
Water Resources Engineer
Meliora Environmental Design
Phoenixville, PA

Expert Testimony within Past Three Years

Jan 2012 **London Grove Zoning Hearing Board;** Testimony on behalf of Three Groves Ecovillage Development, L.P., related to site design engineering components and conformance to local ordinance standards for conditional use approval.

2010 **Butler County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Butler County Act 167 Stormwater Management Plan.

2010 **Crawford County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Crawford County Act 167 Stormwater Management Plan.

2010 **Mifflin County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Mifflin County Act 167 Stormwater Management Plan.

2010 **Montour County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Montour County Act 167 Stormwater Management Plan.

2010 **Potter County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Potter County Act 167 Stormwater Management Plan.

2010 **Venango County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Venango County Act 167 Stormwater Management Plan.

2010 **Warren County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Warren County Act 167 Stormwater Management Plan.

2008-2011
Civil Engineer Manager and Sr. Civil Engineer
Comm. of Pennsylvania:
PA Dept. of Env. Prot.
(Bur. of Aban. Mine Rec.)
(Bur. of Watershed Mgmt.)
PA Dept. of Transportation
(Bur. of Maint. And Oper.)
Harrisburg, PA

2006-2007
Project Manager
Navarro & Wright Consulting Engineers, Inc.
New Cumberland, PA

2006-2006
Project Designer
Raudenbush Engineer, Inc.
Middletown, PA

2005-2005
Project Designer
Morris & Ritchie Associates
York, PA

2004-2005
Transportation Engineer I
Buchart-Horn, Inc.
York, PA

Professional Memberships

Member, American Society of Civil Engineers, Environmental Water Resources Institute

Expert Analysis and Comment within Past Three Years

2011 **AML-1: The Abandoned Mine Land Inventory Manual;** on behalf of the Pennsylvania Department of Environmental Protection, Bureau of Abandoned Mine Reclamation; Technical review and comment of revisions to the Department of interior, Office of Surface Mining's regulatory standards for addressing abandoned mine lands.

2011 **Alternate Pavement Type Bidding**: on behalf of the Pennsylvania Department of Transportation, Bureau of Maintenance and Operations; Expert analysis of alternate pavement type bidding policies as implemented on highway design projects in Pennsylvania.

Publications

Streambank Stability: Modeling Channel Evolution and Pollutant Transport in an Urban Stream; Ruth A. SItler; Pennsylvania State University, Masters Paper; Dec 2010.

Geographic Variability of Rainfall Erosivity Estimation and Impact on Construction Site Erosion Control Design; Shirley E. Clark, Aigul Allison, and Ruth A. Sitler; *Journal of Irrigation and Drainage Engineering*; American Society of Civil Engineers; July 2009.

Special Experimental Project No. 14 (SEP-14) Alternate Pavement Type Bidding Initial Report; Pennsylvania Department of Transportation and the Federal Highway Administration; Feb 2011.

Porous Asphalt Pavement: 20 Years and Still Working, Michele Adams, Published in Stormwater Magazine May/Jun 2003

Presentations and Conference Proceedings

2011

Sep Low impact Development Symposium; Ruth A. Sitler; "Impact of the Rainfall Event Method on the Water Capture Quantity Efficieny of Bioretention Devices"

May 2011 World Environment & Water Resources Congress; Ruth A. Sitler and Shirley E. Clark; "Impact of Bioretention Design of the Calculation Method for the 95th Percentile Rain Event"

2009

Mar "Act 167 Stormwater Management;" Harrison City, PA

May 2009 World Environment & Water Resources Congress; Christine Y. Siu, Shirley E. Clark, Ruth A. Sitler and Katherine Baker; "Looking Upstream and Into the Watershed for the Big Picture of Stream Health"

June "Act 167 Stormwater Management – Municipal Implementation Models;" Mercer, PA

July "Introduction to Hydrologic Modeling with HEC-HMS;" Harrisburg, PA
"Building a Project and Running a Simulation with HEC-RAS;" Harrisburg, PA

Oct 2009 Pennsylvania Stormwater Management Symposium; Ruth A. Sitler, Aigul Allison, and Shirley E. Clark; "Geographic Variability of Rainfall Erosivity Estimation and Impact on Construction Site Erosion Control Design"

2008

Feb "Small Watershed Hydrology Modeling with WinTR-55;" Middletown, PA
"AutoCAD;" Middletown, PA
Mar "Erosion Control and NPDES Permitting;" Middletown, PA
Apr "Introduction to HEC-RAS;" Middletown, PA
"HEC-HMS: The Hydrologic Engineering Center's Hydrologic Modeling System;" Middletown, PA
May "Planning to Protect Water Resources: Stormwater Management;" Hershey, PA
Sep "Understanding the Regulatory Environment: DEP Headwaters Initiatives and Stormwater BMPs;" Monroeville, PA
Oct "Integrated Water Resource Planning through Act 167;" Harrisburg, PA
Nov "Stormwater Management: Act 167 and Its Implementation;" Harrisburg, PA

2007

Mar "Engineering Overview of Erosion Control and NPDES Permitting in Central Pennsylvania;" New Cumberland, PA
Oct 2007 Pennsylvania Stormwater Management Symposium; Ruth A. Sitler and Shirley E. Clark; "Streambank Stability: Modeling Channel Evolution and Pollutant Transport in an Urban Stream"

NIEK VERAART, AICP, ASLA Project Manager

Mr. Veraart is vice president with LBG with more than 20 years of diverse experience in environmental planning, including EIS in accordance with NEPA, SEQRA and CEQR and other environmental statutes. His environmental planning assignments have encompassed a wide range of projects, including transportation infrastructure (airports, highways, ports, rail/transit) industrial facilities (solid waste management, energy, water and wastewater facilities), large-scale development projects (residential, commercial, mixed use, recreational and transit-oriented development), ecological and sustainable development (watershed management, LEED compliance, waterfront restoration, wetland banking) and cultural resources (memorials, tourist attractions, national parks). He is familiar with regulatory requirements at federal, state, and local levels and has integrated such requirements on multilevel environmental documents, including such high-profile assignments as the World Trade Center Memorial and Redevelopment GEIS. Mr. Veraart is especially familiar with construction impacts and assisted federal and state agencies with the development of Environmental performance Commitments (EPCs) for the rebuilding of Lower Manhattan. Mr. Veraart is familiar with upstate watershed issues through his completion of several SEQRA assignments, including an EIS for the Hackensack River in Clarkstown, New York; infrastructure improvements for the Bear Mountain Bridge (for NYSDOS); and the EIS for Kensico Watershed Water Pollution Control Program (for NYCDEP). Mr. Veraart's experience with third-party EIS review is extensive and includes multiple EISs for US Army Corps of Engineers, EIS review for local public interest environmental organizations and for the New York State Public Service Commission.

Several of the projects led by Mr. Veraart have received prestigious state and national awards. Mr. Veraart has presented at national conferences on subjects of environmental planning and his research contributions in the transportation and environmental planning fields have been published by the National Academy of Sciences, Transportation Research Board.

FIRM Louis Berger Group

EDUCATION

- MS, Regional Planning and Land Planning
- BS, Land Planning and Landscape Architecture

REGISTRATIONS / CERTIFICATIONS

- American Institute of Certified Planners
- American Society of Landscape Architects
- American Society of Civil Engineers, Affil.
- International Association for Impact Assessment

YEARS EXPERIENCE 24
YEARS WITH FIRM 16

RELEVANT PROJECT EXPERIENCE

Lower Manhattan Development Corporation (LDMC), GEIS for World Trade Center Memorial and Redevelopment Plan (SEQRA, NEPA EIS), New York, New York. Project director. Mr. Veraart directed LBG's work for the WTC GEIS, which was co-prepared by LBG with another consulting firm. Under Mr. Veraart's direction, transportation analyses were conducted for the redevelopment of the World Trade Center site and construction scenarios were developed for input into the Traffic, Air Quality and Noise analyses. The GEIS process for this high-profile; complex project was completed within a record time of 12 months from the start of environmental review. Mr. Veraart also directed noise, infrastructure, utilities as well as issues of cumulative impacts.

US Army Corps of Engineers New York District, Third-Party EIS, Meadowlands Mills Regional Mall, Bergen County, New Jersey. Project director. Mr. Veraart was Task manager for the independent third-party review of the developer's EIS and preparation of a federal FEIS and Section 404(b) Permit Alternatives Analysis for the development of a 600-acre site for the construction of a mixed use regional mall, office and recreation complex, located three miles from New York City. The project would involve the filling of approximately 200-acres of wetlands and extensive wetland creation and enhancement.

US Army Corps of Engineers New York District, Meadowlands Comprehensive Restoration Implementation Plan Programmatic Environmental Impact Statement, New Jersey. Provided QA/OC review of the Programmatic Environmental Impact Statement (PEIS) for the Meadowlands Comprehensive Restoration Implementation Plan (MCRIP). The PEIS provides an evaluation of environmental, social and economic issues and alternatives to achieve project goals and objectives, while avoiding/minimizing adverse impacts, providing the USACE with the necessary NEPA compliance documentation for MCRIP implementation. The PEIS is a comprehensive document that considers a number of related actions proposed in the MCRIP, including cumulative, direct, and indirect impacts.

New York City Department of Environmental Protection, Kensico Watershed Water Quality Sustainable Management Plan EIS, Westchester County, New York. Project manager. The EIS evaluated the beneficial effects on water quality resulting from several alternative measures, including the development of stormwater Best Management Practices (BMPs), such as wetland basins, streambank stabilization and waterfowl management. Pollutant reductions were subsequently modeled for each of the streams and subwatershed discharging into the Kensico Reservoir. Transport of contributing pollutants within the reservoir and to the water intakes was then modeled. In addition to the evaluation of the effectiveness of various program alternatives, their impact on the environment was assessed,

including socioeconomic and ecological impacts.

Metropolitan Transportation Authority New York City Transit, Fulton Street Transit Center NEPA EIS, New York, New York. Project director. Directed the preparation of the FEIS and Section 4(f) for the $1.4B federally funded Fulton Street Transit Center (FSTC) in Lower Manhattan. Mr. Veraart supervised the approach to alternatives analysis and cumulative effects analysis and supervised preparation of technical assessment of environmental impacts, including traffic and transportation, air, noise, socio-economic analyses and the analysis of adaptive reuse of the historic Corbin Building in Lower Manhattan. A key aspect of the analysis was the assessment of cumulative impacts of the FSTC and other Lower Manhattan Recovery Projects. Mr. Veraart presented the analysis of cumulative construction in Lower Manhattan to a National Panel of government agencies under auspices of the FTA.

US Department of Agriculture, Final Environmental Impact Statement (FEIS - SEQRA, NEPA) Gull Hazard Reduction Program, JFK International Airport, Jamaica, New York. Project manager. Managed the preparation of the SEQRA/NEPA EIS for the implementation of the Gull Hazard Reduction Program at JFK International Airport in New York City.

Parcel B EIS Third-Party Review and Environmental Support Services, Purchase Environmental Protection Association, Purchase, New York. Project manager. Analyzed SEQRA documentation submitted for an office development in Purchase, New York. The expert review team lead by Mr. Veraart reviewed all relevant aspects of the analyzed by the developer and identified numerous deficiencies and inaccuracies in the environmental documentation, including historic resources (impacts on Olmstead landscapes and resources listed on the State/National Register of Historic Places), flooding and stormwater management, incompatibility with zoning regulations, density inconsistencies, traffic safety and congestion issues, ecological impacts and direct and indirect wetland impacts.

Dormitory Authority of the State of New York (DASNY), Chenango Countywide 911 Communications Upgrade EIS, Chenango County, New York. Project Director. Led the preparation of the SEQRA EIS. The project included a GIS-based viewshed analysis of tower visibility. The viewshed analysis included the identification of sensitive resources (e.g. parks and historic areas) within five miles of each tower. The project objective was to improve emergency services communication capabilities through the construction of six radio communication antenna towers and ancillary infrastructure, and upgrades to facilities at an additional three sites

US Army Corps of Engineers New England District, South Coast Rail Project Third-party NEPA EIS (in progress), Massachusetts. Project manager. Mr. Veraart is managing the preparation of an Alternatives Analysis and NEPA EIS for new 60-mile transit service between Boston and the south coast of Massachusetts, including New Bedford and Fall River. Alternatives being evaluated include Bus Rapid Transit and rail. Key impact areas addressed included wetlands, water resources, threatened and endangered species, noise and vibration and coordination with Native American tribes.

Township of Randolph, Third-Party Environmental Review and Site Suitability Analysis Services, Randolph, New Jersey. Project manager. Conducted an independent third-party review of the environmental documentation for the 154-acre Nitti Mountain development project in the Township of Randolph, New Jersey. The review assessed all applicable resources including soils, geology, wetlands, hydrology, slopes/engineering, ecology; land use and zoning, landscape and visual, traffic/circulation and access, cultural resources and socioeconomic impacts. The report provided comments and recommendations regarding technical methodologies, data gaps and data quality, compliance with applicable regulations and appropriateness, projected cost and feasibility of proposed mitigation measures.

City of New City, New York, FEIS, Hackensack River Natural Area Improvement and Flood Management Project, Clarkstown, New York. Project director. Mr. Veraart directed the preparation of the FEIS for flood control measures in the Hackensack River. Flood control measures include the construction of backwater prevention berms, dredging of river sediment and widening of the river in order to improve flow.

NYS Bridge Authority, EA (SEQR) Bear Mountain Bridge Rehabilitation, Bear Mountain,

New York. Project director. Directed environmental permitting and regulatory issues for rehabilitation of the Bear Mountain Bridge across the Hudson River.

Port Authority of New York and New Jersey, Newark Liberty International Airport, Terminal A NEPA Draft Environmental Assessment. Newark. New Jersey. Project manager. Preliminary Environmental Assessment for construction of a new Terminal A facility, including a 1.3 million sf. airport terminal building, surrounding site conditions, including streams and wetlands, roadways and airside facilities. The EA was prepared in close coordination with sustainable planning and design efforts ongoing concurrently towards a LEED certified facility.

LMDC and the National September 11 Memorial & Museum, Pedestrian Simulation Modeling - World Trade Center (WTC) Memorial, New York, New York. Project director. Oversaw the development of origin/destination projections for pedestrian travel patterns on the World Trade Center (WTC) Memorial including the plaza, visitor's center, and museum and the entire WTC Site for the opening year and stabilized year of the WTC Memorial on both a weekday and Saturday. Also developed assumptions for the development program, pedestrian profiles, pedestrian itineraries, and site demand projections. The projected pedestrian movements were modeled to determine if adequate space would be provided for pedestrians based upon the site design and site plan

State University of New York at Binghamton. New Student Housing, State. Town of Vestal, Broome County, New York. Project Director. Directed the preparation of a SEQRA EAF and Supplemental Studies for replacing the 40 years old Newing and Dickinson residence buildings with new buildings to accommodate approximately 3,000 students on the East Campus of Binghamton University. The impact assessments focused on a matrix of potentially affected environmental resources, including storm water/wastewater infrastructure, threatened and endangered species, air quality, and noise.

American Marine Rail, LLP, Dredge Permitting, SEQR Environmental Assessment Statement. And Facility Plan Development. American Marine Rail Intermodal Transfer Terminal, Bronx, New York. Project director. Managed the development of facility layout and directed preparation of permits and state and city environmental regulatory review for a 5,200 tons-per-day intermodal barge-to-rail facility solid waste transfer station. Mr. Veraart supervised the preparation of a Title 6 NYCRR Part 360 Solid Waste permit application to the New York State Department of Environmental Conservation (NYSDEC), a Joint Tidal Wetland Permit from the NYSDEC and the USACE and air quality compliance, as well as compliance with other regulatory requirements**.**

South Jersey Transportation Authority (SJTA) Alternative Energy Vehicle Deployment Plan. Project Director. Directed the preparation of an AEV deployment plan for SJTA, pursuant to the SJTA Alternative Energy Management Plan, prepared by The Louis Berger Group for SJTA. Specific four areas included evaluation of Alternative Energy sources for the SJTA fleet and operations, as well as users of SJTA facilities. Alternative energy sources evaluated include electric, Compressed Natural Gas (CNG), biodiesel and hydrogen.

National September 11 Memorial, Economic Impact of National September 11 Memorial. Project director. Directed the study to analyze impact of the National September 11 Memorial operations on the economy of New York City, New York State and the U.S. Impacts are driven by Memorial operational expenditures, employee household spending and visitor spending. Assessed the effect of the Memorial on Lower Manhattan in terms property tax revenues and business revenues.

NYCDOS, Draft Environmental Impact Statement (DEIS - SEQR, CEQR), Fresh Kills Landfill, Staten Island, New York. Project director. Executive responsibility for the preparation of the DEIS for the Fresh Kills Landfill on Staten Island. For the continued operation of the 2,200-acre landfill, NYCDOS applied for a NYCRR Part 360 Permit for a solid waste management facility from the New York State Department of Environmental Conservation (NYSDEC). For this purpose, the NYCDOS submitted an EIS pursuant to both State Environmental Quality Review (SEQRA) and City Environmental Quality Review. The DEIS was deemed complete by NYSDEC prior to the City's decision to close the Fresh Kills Landfill.

RAED EL-FARHAN, PHD Principal-in-Charge

Dr. EL-Farhan, vice president of LBGs science and water resources division, has more than 20 years of experience as a consultant, professor, and university researcher. His areas of expertise include water resources, ecosystem restoration, stormwater management, water and wastewater treatment systems, water quality permitting and compliance, aquatic chemistry, and the fate and transport of contaminants in the environment. Dr. EL-Farhan has used this diverse expertise in support of EPA headquarters and its regional offices in their BEACH, EMPACT, and TMDL programs, where he has characterized, assessed, and modeled water quality; wrote and reviewed technical reports; and prepared training materials and workshops. He has worked extensively with various states to provide water resources planning services throughout the Mid-Atlantic region, and continues to support the EPA's Assessment and Watershed Protection Division through the Technical Support for the National Watershed Protection Program. Dr. EL-Farhan is working on multiple assignments with U.S. Army Corps of Engineers, Institute for Water Resources (USACE IWR), Engineer Research and Development Center (ERDC), Districts, Headquarters, and Assistant Secretary of the Army (CE) to provide technical review of feasibility studies, conduct facilitations at USACE strategic sessions, assist the USACE with development of quality of life metrics, evaluate the USACE model certification process, and evaluate and certify models. Dr. EL-Farhan is a member of the American Water Resources Association and participates in national dialogues related to water resources issues. He also serves on the planning committee of the National Conference on Ecosystem Restoration (NCER) where he has worked alongside many of the USACE restoration experts.

FIRM Louis Berger Group

EDUCATION

- PhD, Environmental Engineering
- MS, Environmental Engineering
- BS, Civil Engineering

YEARS EXPERIENCE 21
YEARS WITH FIRM 10

RELEVANT PROJECT EXPERIENCE

USACE Kansas City, Project Initiation and Planning for Programmatic EIS for the Missouri River Recovery/Restoration Plan and the Public Relations Strategy and Internal Communication Plan Needs Assessment for the Missouri River Recovery Program. Director. Dr. EL-Farhan worked closely with the project manager to coordinate the technical leads, experts, academics, and subconsultants. He not only provides management, but also technical support. He is providing technical support and is responsible for the development of the Research Compendium that will serve as the scientific guideline and basis during the alternatives development phase of the project. Also, Dr. EL-Farhan is assisting with the development of the public outreach and communications strategy and plan for implementation for the Missouri River Recovery Program. This includes both an external public relations strategy and an internal communications plan.

USACE Baltimore, Anacostia River Watershed Restoration Plan. Program manager. Managed a comprehensive watershed restoration plan for the Anacostia River Watershed; its objective is to produce a systematic 10-year restoration plan for environmental and ecological restoration within the entire watershed to mitigate the impact of stormwater runoff to the Anacostia River watershed. The plan was conducted under the USACE General Investigations Program. The study was authorized in a resolution of the Committee on Public Works and Transportation, U.S. House of Representatives.

USACE IWR, Analytical and Professional Support Services. Program manager for this $25 million, five-year contract that provides technical and analytical support services that are generally not available within USACE, including the following principal areas: program management, water resources, environmental protection and restoration, navigation, information systems, and homeland security. Under this contract and Dr. EL-Farhan's leadership, LBG is providing technical review of feasibility studies, conducting facilitations at USACE HQ strategic sessions, assisting USACE with development of quality of life metrics, evaluate the USACE model certification process and certifying models.

USACE Mobile District IDIQ for Environmental Studies for BRAC Actions. Program manager. Under $6 million IDIQ contract, Dr. EL-Farhan oversees overall project management, subcontractor management, project scheduling, quality assurance and control, deliverable production, project accountability to USACE Mobile, and maintains the administrative record. Currently working on environmental, engineering, and planning services in preparation of Phase II of the feasibility study and EIS for the ecosystem restoration and flood damage reduction for the 23 square-mile Upper Turkey Creek Basin in Kansas. Scope includes engineering analysis for the plan formulation to accomplish flood protection, environmental restoration, and improve water quality and recreational facilities.

USACE Baltimore, IDIQ for Planning Projects, Various Locations. Program manager. Under $5 million IDIQ contract, LBG is managing multiple task orders, preparing siting and facility studies and other planning documents. Specifically, Dr. EL-Farhan has worked on Potomac

Park Levee–EA and Section 106 project, for design and construction of an improved flood control project within the National Mall and Constitution Gardens in Washington, DC, to address the potential impacts to cultural and environmental resources. Also includes St. Martin Ecosystem Restoration–assisted in the evaluation of the feasibility study for aquatic ecosystem restoration in the St. Martin River Watershed in Maryland, under the authority of Section 206 of WRDA.

EPA Assessment and Watershed Protection Division, Technical Support for the National Watershed Protection Program. As program and project manager, developed dozens of watershed TMDL studies nationwide and has prepared training materials and conducted workshops. For these projects, conducted source assessment and watershed characterization to support watershed simulation and development of allocations. Presented TMDL results at a series public meetings. The Bayou Lafourche TMDLs, Louisiana included a comprehensive water quality monitoring plan, developing and submitting a QAPP for EPA's approval, setting up and calibrating Louisiana's QUAL2E model, and calculating the TMDL for the bayou.

Review of the Upper Mississippi River Illinois Waterway Feasibility Report. To help ensure the adequacy of this recommendation to Congress, Dr. EL-Farhan and the LBG team provided a review of the UMRS Chief's Report, the Rock Island District Commander's Feasibility Report, the NRC Reports on the UMRS, and related documents. The purpose of the review was to evaluate the actions proposed by the Chief of Engineers and District Commander in relation to external reports by the NRC and other parties, as well as prior Assistant Secretary of the Army (CW) correspondence to OMB to determine potential courses of action for the Assistant Secretary of the Army (CW) in transmitting his report to OMB and the Congress. The LBG report highlighted known and unknown information relevant to the ability to recommend an action to Congress, noted any deficiencies in needed information and recommended an appropriate course of action.

Transportation Research Board (TRB) of the National Academies. Senior technical reviewer. Dr. El-Farhan serves as a senior technical reviewer for the Transportation Research Board of the National Academies. He is responsible for reviewing documents and providing recommendations. Dr. El-Farhan will be reviewing papers for consideration as part of the program for the TRB 87th Annual Meeting in January 2008 and publication in the Transportation Research Record.

EPA Region 3, pH TMDL for Buckhannon River, West Virginia. Served as technical support for TMDL development for Acid Mine Drainage. Screened the available water quality data for the Buckhannon River to determine the frequency of water quality standards violation of pH and heavy metals. Reviewed models and methods applicable for predicting instream pH in streams. Developed a mass balance model based on inflow of alkalinity and acidity to predict the instream pH of the Buckhannon River.

HOPE LUHMAN, PHD, RPA Cultural Resources

Dr. Luhman manages LBG's New England and Northeast cultural resource operations from the Albany, New York, office. She is responsible for all archaeological, architectural, and historic preservation planning projects involving historic and precontact resources, as well as general business development. Dr. Luhman coordinates interdisciplinary and multitask studies; interfaces with clients and subconsultants; participates in public outreach and education programs; maintains project schedules; evaluates budgets; prepares technical reports, agreement documents, and special exhibits; and provides expert witness testimony.

FIRM Louis Berger Group

EDUCATION

- PhD, Anthropology
- MA, Anthropology
- MA, Social Relations
- BA, Anthropology

REGISTRATIONS/ CERTIFICATIONS

- Accredited by the Register of Professional Archaeologists

YEARS EXPERIENCE 28
YEARS WITH FIRM 16

RELEVANT PROJECT EXPERIENCE

Immigration and Naturalization Service (INS), Phase I and II Archaeological Survey, INS Border Patrol Station, St. Lawrence County, New York. Principal investigator.

GSA Northeast and Caribbean Region, Photographic Documentation, Phase IB Archaeological Survey, and Data Recovery Investigations, Proposed U.S. Courthouse, Buffalo, Erie County, New York. Project manager/principal investigator.

New York Army National Guard, Cultural Resource Surveys: New York Army National Guard (NYARNG). Project manager/principal investigator. Projects have included Phase IA archaeological surveys for the Rome, Lockport, Jamestown, Dunkirk, Cortland, and Dryden armories; Phase IA and IB surveys for the Walton, Kingston, Leeds, Latham, Orangeburg, Geneseo and proposed Queensbury armories; Phase IB survey for the Auburn Armory; and Phase II and III archaeological investigations for the Kingston Armory.

PARS Environmental for 77th Regional Readiness Command, Phase IB Archaeological Survey, Kerry P. Hein United States Army Reserve Center, Town of Shoreham, Suffolk County, New York. Project manager/principal investigator.

PARS Environmental for 77th Regional Readiness Command, Section 106 Compliance, Rocky Point/Brookhaven Nike Missile Launch Facility, Shoreham, Suffolk County, New York. Project manager/principal investigator.

77th Regional Readiness Command, Phase IA Archaeological Surveys, New York and New Jersey. Project manager/principal investigator.

U.S. Army Corps of Engineers (USACE) Mobile, Phase I Archaeological Survey, Fort Totten BRAC, Queens County, New York. Project manager/principal investigator.

Engineering Field Activity Northeast, Naval Facilities Engineering Command (NAVFAC), Archaeological Monitoring, Palmer Hall Geothermal Loop Field, U.S. Merchant Marine Academy, King's Point, New York. Project manager/principal investigator.

U.S. Military Academy, Cultural Resources Support, Family Housing, USMA, West Point, New York. Project manager/principal investigator.

Engineering Field Activity Northeast, NAVFAC, Archaeological Monitoring, Barry Hall Geothermal Loop Field, U.S. Merchant Marine Academy, King's Point, New York. Principal investigator.

Denver Service Center (DSC), Direct Labeling of Artifacts Recovered from the Archeological Excavations Conducted at Fort Stanwix National Monument for Willett Center Construction, Oneida County, New York. Project manager.

Phase I Archeological Survey, Proposed Mongaup Interpretive Center, Upper Delaware Scenic and Recreational River, Lumberland, Sullivan County, New York. Project manager/co-principal investigator and cultural resource task leader.

Archeological Survey for Roosevelt Farm Lane Rehabilitation Project, Home of Franklin Roosevelt National Historic Site, Hyde Park, Dutchess County, New York. Project manager.

Archeological Survey for the Construction Staging, Sediment Dewatering, and Sediment Dispersal Areas, Val-Kill Pond Restoration Project, Eleanor Roosevelt National Historic Site, Hyde Park, Dutchess County, New York. Project manager.

DASNY, Report on the Phase II and III Archaeological Investigations, The DASNY Site, 515 Broadway, Albany, Albany County, New York. Project manager.

DASNY, Phase IA Newing College Dormitory, State University at Binghamton, Broome County, New York. Project manager.

DASNY, Phase IA Archaeological Survey, Chenango Countywide 911 Communications System Upgrade, Chenango County, New York. Project manager.

Ammann & Whitney, and New York State Bridge Authority, Cultural Resource Services, Bear Mountain Bridge Cable Strengthening Study, Rockland and Westchester Counties, New York. Project manager.

Ammann & Whitney, Phase IA Cultural Resource Sensitivity Assessment, Proposed Amsterdam Pedestrian Bridge, City of Amsterdam, Montgomery County, New York. Project manager.

EBI Consulting, Cultural Resource Services for Wireless Carriers, New England. Contract and project management/principal investigator. On-call contract for performance of cultural resource surveys in New York, Massachusetts, New Hampshire, Vermont, Connecticut, Rhode Island, and Maine. Archaeological desk reviews, archaeological resource assessment reports, and reconnaissance/intensive surveys have been conducted throughout New York, Massachusetts, New Hampshire, Vermont, Connecticut, and Rhode Island.

USACE New England, Review of Cultural Resource Investigations, South Coast Rail Project, Southeast Massachusetts. Project manager/principal investigator.

New York State Education Department (NYSED)/New York State Department of Transportation (NYS DOT), Cultural Resource Services. Contract manager. Five-year contract (beginning 2007) to provide cultural resource services primarily associated with NYS DOT Regions 8-11, but may also include other state agency undertakings. Project-specific studies for all phases of archaeological investigations and architectural resource surveys. To date, 28 task orders received; four examples of completed projects are listed below.

- Cultural Resource Reconnaissance Survey, Site Examination and Data Recovery Plan, Shaker/Powell Hotel Site, Route 155 and Old Niskayuna Road Intersection Improvements, PIN 1132.15.101, Town of Colonie, Albany County, New York. Project manager and principal investigator.
- Archaeological and Architectural Reconnaissance Survey, Gorham Street Bridge and Approach Removal, PIN 3805.50.101, Village of Waterloo, Seneca County, New York. Project manager and principal investigator.
- Reconnaissance (Phase I) Survey, Republic Airport Development Aircraft Hangar, PIN 0903.55.101, Town of Babylon, Suffolk County, New York. Project manager and principal investigator.
- Cultural Resource Reconnaissance Survey, Jericho Turnpike, PIN 0042.27.121, Towns of Huntington and Smithtown, Suffolk County, New York. Project manager and principal investigator.

EDWARD SAMANNS, PWS, CE Aquatic Ecology

Mr. Samanns is the director of environmental sciences at LBG with more than 20 years of experience managing environmental investigations for a variety of projects and clients. Mr. Samanns specializes in ecological restoration/mitigation and related topics including stream and wetland ecology, permitting, threatened and endangered species studies, invasive species management, and NEPA compliance. Mr. Samanns serves as the project manager/director for several environmental and restoration contracts for public sector clients and was responsible for preparing data collection and analysis protocols, developing and implementing vegetative and hydrology monitoring methodologies, and developing habitat restoration designs. Mr. Samanns is a key member of LBG's ecological restoration unit, a unique assemblage of key scientists and engineers that have been combined to conduct restoration projects including wetland mitigation banks, endangered species habitat enhancement, coral reef creation, and tidal marsh restoration. He was the principal investigator and author of NCHRP Synthesis 302 Mitigation of Ecological Impacts (2002), is currently conducting research for NCHRP on Habitat Fragmentation, and has published/presented several papers on wetland mitigation and wildlife crossings. Mr. Samanns is also a co-author of the USACE, Waterways Experiment Station, Engineering Specification Guidelines for Wetland Plant Establishment and Subgrade Preparation (1998). Mr. Samanns also performs QA reviews of technical reports and restoration designs and provides independent research on environmental topics for clients.

FIRM Louis Berger Group

EDUCATION
- MS, Geography
- BS, Biology

REGISTRATIONS/ CERTIFICATIONS
- Professional Wetland Scientist
- Certified Geologist

YEARS EXPERIENCE 25
YEARS WITH FIRM 23

RELEVANT PROJECT EXPERIENCE

County of Rockland, Minisceongo Creek Nor'easter Repair Project, Rockland County, New York. Project manager. Responsible for overseeing the wetland and stream delineation for the project area and preparation of the Environmental Investigation Report. Also evaluated project for compliance with NEPA CATX requirements of FEMA and coordinated with project engineers to assess project alternatives to stabilize an area of mass wasting and slope failure, protect existing infrastructure from river erosion, re-establish fish passage, and establish self mitigating construction approach. Responsible for ongoing coordination of NYSDEC and ACOE permits for construction.

Marsh Resources, Meadowlands Mitigation Bank Phase 3, Carlstadt, New Jersey. Project director of the permitting, design and upcoming construction of a 60-acre tidal and freshwater wetland mitigation bank in the Hackensack Meadowlands. Responsibilities include federal and state permit application preparation and acquisition, banking instrument preparation, negotiation and approval by the interagency MIMAC, and site concept designs. Analysis has included assessment of on-site resources, functional value assessment, credit determination, innovative designs to minimize wetland fill and control invasive species, tidal data analysis and tide gate assessment. Planting plan also addressed potential treatments for acid soil conditions. Responsible for developing construction and planting plans as a design/build project employing marsh excavation and dredge methods to create enhanced tidal habitat of mud flat and low and high marsh interspersed by tidal channels and upland islands and freshwater forested wetlands.

New York Thruway Authority and NYSDOT, Stewart Airport Access Improvement, Wetland and Vernal Pool Mitigation Site Selection and Design. Project manager. Responsible for conducting a site selection and design study for the creation of 1.5 acres of vernal pool habitats within forested uplands to compensate for wetland habitat losses as requested by the NYSDEC. Evaluated physical features within project area leading to the identification of potential sites. Developed concept plans for each vernal pool site. Also responsible for the design of 15 acres of forested, scrub shrub and emergent wetlands at an off-site location. Prepared full plans and specifications to support bid documents. Additional task included preparation of a Biological Assessment for the Federal and State endangered Indiana bat along the project corridor, and coordination with the USFWS and NYSDEC.

PANYNJ, Goethals Bridge Replacement Project, Staten Island. Project supervisor. Responsible for overseeing the tasks related to the preparation of the natural resource components of a NEPA EIS and the preparation of environmental permits required for issuance of the Record of Decision by the US Coast Guard. Also supervising the wetland mitigation site selection and wetland mitigation design tasks that are necessary to support the preparation of a Mitigation Plan for the Corps permit application. Permit applications include addressing purpose and need, alternatives analysis, coastal zone consistency reviews, EFH assessments, and other topics.

USACE Baltimore District, Integrated Natural Resource Management Plan Environmental Support Services, 99th Regional Readiness Command. Project supervisor. Responsible for overseeing the preparation of an Invasive Species Management Plan and Endangered Species Management Plan as part of an INRMP for use on 184 properties in five states under the command of the 99th Regional Readiness Command. The invasive species management plan was developed to maintain compliance with EO 13112 Invasive Species and the Army Policy Guidance for Management and Control of Invasive Species. The endangered species management plan was updated to maintain compliance with the Endangered Species Act, Bald and Golden Eagle Protection Act, DoD Instruction 4715.3, and AR 200-3. The management plans address existing conditions and habitats, target species and appropriate management actions and estimated costs.

Molly Ann Brook Watershed Management Plan, Passaic County, New Jersey. Project director. Responsible for the coordination and completion of all field studies, meetings, workshops, report preparation, staffing, schedule and budget for this project. The project involves development of a Geodatabase as part of a watershed characterization effort that includes Rosgen stream reach classification, USGS Visual Assessments, and point source locations. Baseline analysis also included collection of hydrologic data and development of stream rating curves, incorporation of fecal coliform and other water quality data, benthic macroinvertebrate data, and assessments of potential nonpoint pollution sources within watershed. Prepared and conducted two public workshops to educate and gather information from interested citizens and public officials. Developed a prioritized list of effective BMP's and prepared a concept design and constructability assessment of the six best candidates for installation.

PANYNJ, Environmental Assessment, Newark Airport, Newark and Elizabeth, New Jersey. Environmental scientist. Responsible for overseeing the preparation of natural resource sections of an FAA Environmental Assessment (EA) for the expansion and modernization of Terminal A at Newark Liberty International Airport. Provided oversight of field investigations and baseline conditions analysis. In addition, provided technical input on options to minimize and mitigation wetland and open water impacts on-site through the use of innovative design options.

Brookhaven Science Associates and US Department of Energy, Peconic River Restoration Project, Brookhaven National Laboratory, Suffolk County, New York. Project manager. Responsible for the development and implementation of a Wetland Restoration Design as part of a three phase remediation of 14,700 linear feet of contaminated stream and freshwater wetlands. Also prepared and obtained NYSDEC wetlands equivalency permits, and long term monitoring plan. Project included developing a habitat assessment for the state threatened Banded Sunfish, developing and implementing protocols for the collection and transplanting of wetland plant material into restored wetlands, and collection and transplanting dormant trees using tree spades.

NYSDOT, Term Agreement for Ecological and Water Resource Studies, and Training. Project manager. Responsible for managing three consecutive four-year on-call services term agreement to provide wetland and water services to NYSDOT Regions 8, 10 and 11, and other upstate regions. Services performed include the delineation of state and federal regulated wetlands, wetland functional assessments, wetland permitting support under the New York State Freshwater Wetlands Act and Section 404 of the Clean Water Act, stream assessments and restoration design, and water quality assessments modeling. Additional services include providing training to NYSDOT staff, evaluating alternative alignments to avoid, minimize and reduce wetland impacts, evaluate wetland mitigation sites, and conducting and preparing wetland mitigation monitoring reports for submission to USACE/NYSDEC. Over one hundred task orders have been completed.

Federal Bureau of Prisons, NEPA EA/EIS Preparation for Proposed Federal Correctional Facilities Nationwide. Team leader. Conducting wetland delineations, wetland assessments, biological inventories, and impact assessments for multiple EAs and EISs for proposed federal prison facilities. Also performed Section 404/State 401 permitting and mitigation site selection and design for several of the projects. Managed staff, subconsultants, and report preparation to complete tasks on time and on budget. Projects are located in over fifteen states and have required interaction with state regulatory agencies and USFWS.

LEO TIDD Noise, Land Use, Indirect and Cumulative Impacts

Mr. Tidd's work at LBG has been focused on conducting environmental analyses for proposed projects and preparing documents to demonstrate compliance with state and federal environmental laws and regulations. He has been lead author and editor of complex EISs required as a result of prior environmental litigation. On these projects Mr. Tidd serves as the primary author, synthesizing the work of various technical specialists into a logical and concise narrative that addresses regulatory compliance and ensures that the lead agency took the requisite "hard look" at environmental issues. In addition, he is responsible for technical environmental analyses on topics that include, noise, indirect and cumulative impacts, air quality, habitat fragmentation/edge effects, wetlands and water resources. Mr. Tidd has completed noise impact modeling for a new connector roadway to the Atlantic City International Airport in New Jersey, as well as comprehensive noise evaluations for off-road vehicle use at the National Park Service (NPS) at Yellowstone National Park and the Lake Meredith National Recreation Area. Mr. Tidd has prepared or contributed to the indirect and cumulative impact assessments for several projects where litigation on indirect and cumulative impact issues occurred in the past or is anticipated, including the Circ-Williston Transportation Project in Vermont, the I-93 Improvements Project in New Hampshire, the Gaston East- West Connector in North Carolina, and the Birmingham Northern Beltline in Alabama. Mr. Tidd is a contributing author of the Legal Sufficiency Criteria for Adequate Indirect Effects and Cumulative Impacts Analysis as Related to NEPA Documents report prepared for AASHTO Standing Committee on the Environment as part of NCHRP Project 25-25.

FIRM Louis Berger Group

EDUCATION

- MPA, Environmental Science and Policy
- BS, Environmental Studies

TRAINING

- Transit Noise and Vibration Impact Assessment, National Transit Institute, 2011
- Highway Traffic Noise: Basic Acoustics, National Highway Institute, 2011
- EPA and FHWA Particulate Matter Quantitative Hot Spot Analysis Training, 2011
- AERMOD Dispersion Modeling Training, Lakes Environmental, 2011
- EPA and FHWA MOVES2010 Training, 2010
- EPA and FHWA Draft MOVES2009 Training, 2009
- Introduction to Transportation Conformity, National Transit Institute, 2008

YEARS EXPERIENCE 6
YEARS WITH FIRM 6

RELEVANT PROJECT EXPERIENCE

Peninsula Corridor Joint Powers Board, Dumbarton Rail Corridor Noise and Vibration Study, California. Task manager. The Dumbarton Rail Corridor Project EIS is being prepared for a proposed new rail service on a corridor spanning San Francisco Bay connecting the existing Caltrain San Jose-San Francisco line alignment in Redwood City, San Mateo County to Newark, Union City and other cities in Alameda County. The noise and vibration study being prepared by Mr. Tidd includes short-term noise monitoring at sensitive receptor locations, train and grade-crossing bell noise impact assessment using Federal Transit Administration procedures, train horn noise impact assessment using Federal Railroad Administration's horn noise spreadsheet program, and a screening analysis of bus noise impacts using FHWA's Traffic Noise Model.

NPS, Yellowstone National Park Winter Use Plan EIS, Wyoming, Montana and Idaho. Planner. Mr. Tidd was the lead author of the EIS chapters addressing the impacts of various levels of snowmobile and snowcoach use on air quality and natural soundscapes as part of the Yellowstone Winter Use Plan Draft EIS. Mr. Tidd summarized the available monitoring data to describe existing conditions in the park, and coordinated extensively with the NPS Natural Sounds program that was responsible for developing the impact thresholds and detailed soundscapes modeling effort. One key challenge addressed by Mr. Tidd was identifying the potential for cumulative impacts to natural soundscapes from actions by others, including oil and gas development in the region, aircraft overflights, and population growth/land development.

NPS, Lake Meredith National Recreation Area Off-Road Vehicle Management Plan EIS, Texas. Planner. Mr. Tidd wrote the EIS chapter describing the existing condition of natural soundscapes within two ORV areas based on monitoring data of percent time audible and sound levels. Mr. Tidd also assisted NPS with the development of soundscapes impact thresholds for the various action alternatives under consideration in the management plan and prepared the soundscapes impact assessment. The purpose of the Lake Meredith National Recreation Area Off-Road Vehicle plan/EIS is to manage ORV use in the national recreation area for visitor enjoyment and recreation opportunities, while minimizing and correcting damage to resources.

South Jersey Transportation Authority, Atlantic City Expressway/Atlantic City International Airport Direct Connector Road Noise and Air Quality Studies, Egg Harbor Township, New Jersey. Task manager. Mr. Tidd prepared air quality screening analyses based on changes in level of service and traffic volumes to address Federal Aviation Administration and conformity requirements for a new roadway and interchange in Egg Harbor Township, New Jersey. Mr. Tidd also conducted traffic noise modeling for the project using TNM2.5 and prepared the traffic noise study technical memorandum. Mr. Tidd developed the noise impact criteria for this project based on FHWA and FAA regulations. The noise modeling effort involved 41 receptor locations. In addition, Mr. Tidd prepared GIS mapping illustrating the location of environmental justice communities in the project area using 2010 U.S. Census data.

Vermont Agency of Transportation (VTrans), Circ-Williston Transportation Project EIS, Chittenden County, Vermont. Deputy project manager. The Circ-Williston EIS is a "fresh look" at a transportation project that was stopped as a result of environmental litigation just prior to construction. Mr. Tidd was responsible for editing the EIS and technical reports, creation of a comment database tracking system and was the lead author of the responses to comments on the Draft EIS and Final EIS. Mr. Tidd coordinated extensively with the various technical discipline specialists and subconsultants involved with the project to ensure a comprehensive and legally sufficient environmental documentation. Mr. Tidd's technical accomplishments on this project have included a detailed analysis of wildlife habitat edge effects and fragmentation, a GIS-based wetland mitigation site search analysis, a project-level greenhouse gas emissions analysis, and a deicing salt loading analysis.

New Hampshire DOT, I-93 Improvements (Salem to Manchester) Supplemental EIS (SEIS), New Hampshire. Deputy project manager. Mr. Tidd was the lead author of the I-93 supplemental environmental impact statement (SEIS), which was prepared in response to a court order requiring analysis of the effects of induced population and employment growth on secondary road traffic and air quality. In addition to editing all components of the SEIS, Mr. Tidd was also responsible for several technical analysis tasks, including a regional emissions sensitivity analysis for ozone precursors, and a cumulative impact analysis assessing the aggregate consequences of the project combined with other reasonably foreseeable projects and forecasted levels of population and employment growth in Southern New Hampshire. The project involves widening I-93 from two-lanes to four-lanes in each direction for a distance of 20 miles between the Massachusetts state line and Manchester, New Hampshire.

USACE, South Coast Rail EIS, Massachusetts. Planner. As part of the third-party review conducted by LBG, Mr. Tidd was responsible for the preparation of technical memorandums reviewing proposed methodologies for assessing indirect and cumulative impacts, and greenhouse gas emissions for the South Coast Rail project. Mr. Tidd was also responsible for editing portions of the DEIS/DEIR, assisting with quality assurance reviews and addressing comments on draft documents.

North Carolina Turnpike Authority, Gaston East-West Connector Indirect and Cumulative Effects Study, North Carolina. Task manager. Mr. Tidd prepared a quantitative indirect and cumulative impact assessment for a proposed toll road extending from I-85 west of Gastonia in Gaston County to I-485 near the Charlotte-Douglas International Airport in Mecklenburg County. As part of this study, Mr. Tidd defined watershed-based study area boundaries and developed metrics to translate household and employment growth into indicators for environmental impacts, such as increases in impervious surface cover and loss of forest cover. Mr. Tidd was responsible for developing and implementing the GIS-based analysis methodology for this project, as well as preparing the final technical report.

DASNY, Chenango Countywide 911 Communications Upgrade EIS, Chenango County, New York. Planner. Assisted in preparation of the SEQRA EAF, scoping document and EIS. Responsible for a GIS viewshed analysis of tower visibility using the ESRI 3D Analyst extension. The viewshed analysis included the identification of sensitive resources (e.g. parks and historic areas) within five miles of each tower. The project objective is to improve emergency services communication capabilities through the construction of six radio communication antenna towers and ancillary infrastructure, and upgrades to facilities at an additional three sites.

DANE ISMART Transportation

Mr. Ismart has 28 years experience with FHWA and 11 years with LBG. While with the FHWA, he served in many capacities including area engineer, research engineer, urban planner, and intermodal team leader. As part of the Office of Environment and Planning, Mr. Ismart specialized in systems transportation planning, intermodal planning, traffic engineering, and policy. He is a nationally recognized expert in transportation planning and models, highway capacity analysis, access management, and site impact analysis. During Mr. Ismart's tenure with FHWA, he conducted and authored the materials for more than 400 short courses on quick response urban planning models, traffic operations, freight planning and models, highway capacity, innovative highway and transit finance, transportation and environmental planning, land use planning, access management, and site impact analysis.

FIRM Louis Berger Group

EDUCATION
- MS, Civil Engineering
- BS, Civil Engineering

YEARS EXPERIENCE 28
YEARS WITH FIRM 17

RELEVANT PROJECT EXPERIENCE

Walmart versus Historic Preservation Society of Civil War Battlefields, Orange County, Virginia. Expert witness. Served as an expert witness for the Historic Preservation Society on the traffic impacts of a proposed Walmart development in Orange County, Virginia on the Wilderness Civil War Battlefield.

I-93 SEIS. Technical analyst. Developed traffic forecasts by using the New Hampshire Statewide Traffic Forecasting Model. Various scenarios are being analyzed and the results are being used for determining how well the projects purpose and scope are being met. As part of this project, an estimate of the potential changes in land use and indirect impacts due to adding capacity to the I-93 corridor are being developed.

Intermodal Terminal Innovative Finance Study. Technical writer. Developed a case study for the NCHRP study evaluating innovative funding techniques for improving access to intermodal facilities. The case study was for the Port of Palm Beach's Sky Bridge over Route 1.

Virginia Research Council. Author and instructor. Developed a financial management of federal aid course for Virginia Research Council.

Highways for Life Leap Not Creep Innovation of Technology Course. Subject matter expert technical advisor and senior instructor. Developed technical material on the application of new innovative techniques for long lasting construction and construction techniques to reduce maintenance of traffic delays and construction impacts.

FHWA, Predictive Performance of Traffic Simulation Models. Project manager. Developed a series of case studies for FHWA to assist transportation planners and traffic engineers in applying traffic simulation models. The case studies included several applications of simulation models forecasting traffic during construction as well as after completion of the projects. A brochure and how-to manual for troubleshooting the application of the simulation models to better replicate actual travel conditions was developed.

FHWA, Access Management Primer and Video. Project manager. Developed the FHWA Primer and Videotape entitled, "Safe Access is Good for Business." The primer discusses in detail methods for improving access to business during construction of corridor access improvement projects.

National Highway Institute. Instructor. Certified NHI instructor for the Federal-Aid 101 Course, Access Management Course, Innovation of Technology Course, and the Highway Capacity Course.

Update of Federal-aid 101. Author. Revised the FHWA Federal-aid 101 Course Material. The material was updated to include the latest planning, finance, construction, and environmental requirements required by SAFTEA-LU. The material and curriculum are used to train FHWA personnel.

FHWA Bottleneck Initiative Workshops. Lecturer/ technical advisor. Conducted Regional workshops and created technical material for the FHWA Bottleneck Initiative. The presentation included techniques for identifying potential corridor bottlenecks due to recurring and non-recurring events and applying innovative solutions for maintaining traffic

and reducing delay.

FHWA, Operations CBU Task Order. Key technical task leader. Directed technical teams for a series of FHWA tasks orders involving intermodal planning and policy analysis, freight movements, ITS, and traffic operations.

University of Tennessee, Planning Courses. Instructor. Developed and conducted travel demand forecasting, site impact, access impact, and highway capacity courses for the University of Tennessee and the Tennessee Department of Transportation.

University of Maryland. Instructor and course developer. Developed and conducted site impact, access management, and highway capacity courses for the University of Maryland and the Maryland State Highway Administration.

Central Arkansas Regional Transportation Study. Project manager. Conducted an analysis of the 200-mile freeway system in central Arkansas. The study developed a series of recommendations for improving the freeway system. The study also includes a feasibility study of a fourth bridge crossing over the Arkansas River in Little Rock, Arkansas and a financial plan for funding.

Florida Department of Transportation. Project manager. Conducted a study to evaluate and develop recommendations for improvements to the NHS intermodal connectors of FDOT's District Six.

Klingle Road EIS, Washington, D.C. Traffic technical lead. Conducted the traffic analysis and forecast for the Klingle Road EIS. Using the MWCOG model the project estimated the traffic and traffic patterns if Klingle Road was repaired and open to traffic.

NPS Potomac Boathouse EIS, Arlington County, Virginia. Traffic technical lead. Conducting the traffic analysis to determine the traffic and parking impact for the construction of a new Boathouse facility on the Potomac in Arlington County.

Wisconsin Avenue and Military Road Phase 1 and 2 Corridor Studies, Washington, D.C. Technical director. Conducted a corridor study for the Wisconsin Ave. Corridor and the Military Road Corridor in Washington, D.C. The study developed a series of transportation improvement recommendations for improving the flow of traffic. The study included public meetings and an analysis of future land use development in the corridor.

Washington, D.C., Evacuation Planning Study. Technical model leader. Developed a system-wide traffic forecasting tool to be used in rerouting traffic during man-made and natural disasters that cause corridor or system-wide disruption of traffic.

DC Office of Planning, Washington, D.C. Comprehensive Plan. Model director. Applied the Washington DC COG model as part of the development and evaluation of the Comprehensive Transportation Plan Element.

SHRP 2 R11: Strategic Approaches at the Corridor and Network Levels to Minimize Disruption from the Renewal Process. Principal investigator. Leading the team to create the Work Zone Impact Strategy Estimation (WISE) tool and technical primer. Planning and Operations modules will assist in assessing strategies including economic impact across networks and corridors with user-defined or default value performance measures.

BRAC Bethesda Medical Traffic Study. Traffic engineer. Directing an effort to analyze the impact that the transfer of the Walter Reed staff and patients to the Bethesda Naval Center will have on the access points and internal traffic of the Bethesda Naval Center. A mitigation program to relieve future congestion on the Center is being proposed and developed.

Route 29 Corridor Study, Fauquier County, Virginia. Principal investigator. Analyzing and recommending a series of innovative corridor improvements for Fauquier County, Virginia. A report is being written and improvements such as roundabouts, directional left turns, and restricted access movements are being analyzed.

Kevin Heatley, LEED AP

Employment

2010 – current	Biohabitats, Inc., Baltimore, MD, Senior Scientist
2006 - 2010	Biohabitats Invasive Species Management, Inc., ISM Vice President
2005 - 2006	Penn State College of Technology, Williamsport, PA, Substitute Instructor, Natural Resource Management Department
2005 - 2006	Invasive Plant Control, Inc., Nashville, TN, Director of Development Northeast Region
1997 – 2005	ACRT Inc., Akron, OH, Senior Forester/Regional Manager
1984 – 1994	Bartlett Tree Experts, Lancaster, PA, Area Manager/Arboricultural Consultant

Education

Masters Environmental Pollution Control, Penn State University, Harrisburg, PA, 2006
B.S., Natural Resource Management, Cook College, Rutgers University, New Brunswick, New Jersey 1982

Professional Registration

Certified Arborist #PD-0029, 2000
LEED Accredited Professional for New Construction (USGBC), 2009

Experience

Mr. Heatley has over 20 years of experience in the environmental sector with an extensive background in ecosystem characterization, integrated vegetation management, invasive species suppression and community-based forestry. As a senior ecologist at Biohabitats, Mr. Heatley is responsible for technical and logistical oversight of restoration projects across the continental United States. His work has primarily focused upon the urban/rural interface and on incorporating green infrastructure into sustainable land use planning and management. An expert in the field of invasive species suppression, Mr. Heatley designed the first fully integrated invasive treatment prioritization model in the United States for Fairfax County, Va. He has successfully integrated resource valuation modeling into strategic and budgetary management plans for a variety of land management entities. He has also been instrumental in providing the conceptual design for a leading GIS-based vegetation management software system.

In addition to his technical expertise, Mr. Heatley is skilled at conducting entertaining and informative public speaking engagements and professional workshops. He has lectured on a variety of natural resource topics throughout the United States and the Caribbean.

Representative Project Experience

NPS Revegetation Eastern States IDIQ, Eastern US. Mr. Heatley successfully served as the Biohabitats project manager on a 2.5 million dollar National Park Service Revegetation IDIQ contract. He coordinated and lead project planning and technical assistance services on a wide variety of ecological restoration task orders including revegetation, invasive species control, plant procurement, seeding, plant protection efforts, marsh restoration, and site characterization. Biohabitats has subsequently been awarded a $20 million dollar follow-up contract for National Park Service revegetation services across the Eastern United States and the Caribbean. Mr. Heatley is currently the project manager and technical lead on this contract.

Burgundy Farm Country Day School Ecological Site Assessment, *Alexandria, VA*. Biohabitats Inc. performed an ecological assessment of the campus and developed recommendations for the sustainable use and conservation of the school's asset. Proactive identification of both ecological assets and landscape challenges enabled the School to cost-effectively integrate site ecology into the master planning process.

Fairfax County Parks Invasive Plant Site Prioritization Model, *Fairfax County, VA.* Biohabitats ISM developed a comprehensive response strategy and site treatment prioritization model as a decision-making tool to be used by the Park Authority to rank the relative value of different sites within their approximately 24,000-acre park system. Based on the principle of "protect the best first" the model shifted the focus in the parks system away from "acres treated" towards "acres restored," allowing the County to maximize the return on its investment in invasive plant control by assuring that treatment sites reflect both the core ecological and cultural values that exist.

Lehigh University, *Bethlehem PA.* Desiring to more fully understand potential atmospheric carbon mitigation opportunities on the college campus, Lehigh University contracted with Biohabitats to undertake an analysis of the direct sequestration and avoided emissions associated with the schools landscape tree cover. Utilizing US Forest Service models, Mr. Heatley performed a comprehensive inventory of 600 acres of naturalized forest and over 220 landscape trees. Information gathered was integrated into strategic recommendations for enhancing this forest benefit and achieving a sustainable level of forest canopy.

Duke University*, Durham NC.* Concerned about the need to understand the ecological processes occurring in a high-visibility, centrally-located stand of campus woodland, Duke University contracted with Biohabitats to undertake an ecological analysis and natural capitol valuation of the campus area known as "Chapel Woods". Mr. Heatley inventoried the vegetation, performed an assessment of the functional benefits, and developed a management plan focused upon forest sustainability. As a function of this effort, Mr. Heatley also performed invasive species suppression within the forest understory.

Valley Road Stream Restoration and Riparian Wetland Creation, *Hagerstown, MD.* Mr. Heatley provided technical recommendations and coordinated invasive plant species suppression in support of the Valley Road Stream Restoration project in Hagerstown, MD. Project involved restoration of an urbanized stream corridor and significant modification of a highly disturbed riparian plant community.

Reforestation Consulting & Invasive Species Suppression, *Rockville, MD.* In order to assure the success of a reforestation effort on a 220 acre tract in Rockville, MD., Fallsgrove Associates, a private development firm, contracted with Biohabitats ISM to oversee tree planting and invasive species suppression. Biohabitats ISM developed and implemented a sampling protocol assessing tree stocking levels and produced biannual reports on supplemental planting levels needed to assure adequate canopy cover. As a component of this effort Biohabitats ISM performed planting contractor coordination and oversight. Biohabitats ISM also created a phased, multi-year, invasive plant suppression strategy. After conducting a comprehensive evaluation of the percent cover for each of the invasive species present on the site, Biohabitats ISM created a target metric for measuring the effectiveness of invasive control efforts. Seasonally selective treatments are currently being undertaken by Biohabitats ISM.

Woodland Restoration of Episcopal High School Alexandria, *Alexandria, VA.* Driven by a desire to integrate a 35 acre woodland resource into the fabric of campus life, the Episcopal High School of Alexandria, Va. contracted with Biohabitats ISM to develop a sustainable campus forest management plan and implement invasive species suppression. This effort involved campus ecosystem characterization, functional benefits modeling, and stakeholder vision sessions. Botanical communities on campus were defined and their respective ecosystem services, in the form of air pollutant interception and carbon sequestration, quantified. Several action items identified during the plan development have subsequently been implemented by Biohabitats including; trail design and construction, ecotone modification, and invasive species suppression. Ecotone modification involved the development of a forest edge planting plan addressing issues of wind vectoring and regeneration. Invasive species interventions have been conducted during 2007 and 2008 in a phased approach designed to enhance native regeneration and minimize opportunities for additional invasive colonization of the woodland.

Episcopal High School, *Baton Rouge, LA.* Recognizing the need to integrate sustainable design principles into future development on their 40 acre campus, the Episcopal High School contracted with Biohabitats (in conjunction with NK Architects) to develop a new Master Plan for the school. Mr. Heatley coordinated Biohabitats participation and involvement in this interactive process. He was directly

responsible for developing recommendations and strategies addressing stormwater retrofitting, green infrastructure expansion, and natural capital valuation.

Missionary Ridge Noxious Weed Inventory and Treatment, *Durango, CO.* During the final year of a three year project, Mr. Heatley provided technical oversight and coordinated the GPS/GIS component of the Missionary Ridge invasive species mapping and suppression effort. As part of an adaptive management approach, data collection protocols were modified and additional field staff were hired and trained by Mr. Heatley.

Woodland Management Plan for Episcopal High School, *Alexandria, VA.* Located in the Washington DC metropolitan area, the 150 years of stable land ownership at Episcopal High School has resulted in a significant legacy woodland on the campus. Recognizing the inherent educational, recreational, and inspirational value of their forest, the school contracted with Biohabitats to develop an integrated woodland management plan. The development of this plan involved a GIS-based forest stand delineation, ecological characterization, invasive plant mapping, ecosystem benefits modeling, and stakeholder vision session. As the project manager, Kevin Heatley developed the final document which provides a framework for sustainable management of this green component of the school infrastructure.

Fort Detrick, *Frederick MD.* The US Army operates Fort Detrick on over 1,200 acres of property in Frederick MD. The mixed land use pattern and competing mission objectives create special challenges regarding natural resource management. To aid in understanding field conditions and assist in budgetary justification, Fort Detrick contracted with Mr. Kevin Heatley (in conjunction with Heartwood Consulting LLC.) to undertake a resource analysis and characterization. The primary components of this project included: a GPS Landscape Tree Inventory (with tagging), GIS Database Integration, UFORE Modeling of the Environmental Impact of Forest Stands, and a Five Year Management Plan (with economic tree valuation). Mr. Heatley in addition was contracted with Fort Detrick to undertake a carbon mitigation feasibility analysis. This project examined the potential to use green infrastructure in the mitigation of vehicular greenhouse gas emissions on the base.

Representative Project Experience Prior to Biohabitats

Atkins Arboretum, *Ridgely MD.* Encompassing 400 acres on the Eastern Shore of Maryland, Atkins Arboretum is a unique facility that highlights native plant communities. With strong educational and research objectives as the primary focus of its efforts, the Arboretum enlisted the aid of Kevin Heatley (ACRT Inc.) to develop and implement a GIS-based vegetation database. Mr. Heatley supervised all aspects of the project including; high resolution aerial photogrammetry, GPS mapping of plant communities, the establishment of a thematic research plot layer, and the construction of a multi-thematic, GIS-based, vegetation database.

Tree Preservation Specifications Manual for Association for Zoological Horticulture, *Allison Park, PA.* The Association for Zoological Horticulture, an organization representing the interests of botanists, horticulturalists, and landscape professionals involved with the management of vegetation in zoological parks, contracted with Mr. Heatley for the creation of a set of standard tree preservation specifications. This document was initiated in response to excessive canopy loss during infrastructure construction and renovation projects. It was designed to promote an integrated, comprehensive approach to tree conservation appropriate for vegetation management within the challenging environment of a zoological park. It also contains an extensive specifications section suitable for use as an attachment on construction contracts.

Villanova University Five-Year Canopy Management Plan, *Villanova, PA.* Mr. Heatley as the project manager provided high resolution aerial photogrammetry, GPS/GIS vegetation and infrastructure mapping, and database design, of approximately 250 acres of this historic campus located in Villanova, Pennsylvania.

Swan Point Cemetery Five-Year Canopy Management Plan, *Providence, RI.* Mr. Heatley as the project manager provided GPS/GIS vegetation and infrastructure mapping, “seamless” GIS providing a work tracking database, and budget information of over 300 acres of this historic cemetery located in downtown Providence, Rhode Island.

Professional Associations

Society of American Foresters
International Society of Arboriculture
Society of College & University Planners

Selected Publications, Technical Reports & Presentations

Greater Everglades Ecosystem Restoration Conference, Naples, Fl, July 2010

Land Trust Alliance Annual Rally, Portland , OR, November 2009

Professional Grounds Management Society, Louisville, KY, October 2009

Mid-Atlantic Exotic Pest & Plant Council, Johnstown, PA. July 2009

Society of American Foresters, Western New York Chapter, April 2008

11th Caribbean Urban Forestry Conference, St. Croix, Virgin Islands, June 2006

St. Croix Environmental Association Tree Conservation Workshop, St. Croix, Virgin Islands, June 2006

Southeast Exotic Pest & Plant Council Annual Meeting, Raleigh, NC, May 2006

Association for Zoological Horticulture, *Tree Preservation Specifications Manual* (Industry Standard), 2005

Penn State Invasive Pest, Plants & Weeds Workshop, Luzerne County, PA, October 2005.

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CURRENT POSITIONS

2007-present Natural Resources Defense Council, New York, NY
Senior Scientist, Global Warming and Health Project
Conduct research and offer educational outreach to the public and policymakers on the impacts of climate change on health. Leads NRDC's Global Warming and Health Project. Among the scientists participating in the Intergovernmental Panel on Climate Change 2007 Fourth Assessment Report; published research has looked at heat- and smog-related health problems, climate change's effects on pollen, allergies and asthma, flooding and infectious diseases, especially among vulnerable communities.
(see www.nrdc.org/climatemaps)

2005- present Mailman School of Public Health, Environmental Health Sciences Department
Columbia University's Climate and Health Program
Assistant Clinical Professor
Teaching and research on the health impacts of climate change, and devising strategies to increase societal preparedness to cope with global warming.

2011-present: Co-Convening Lead Author for the Human Health chapter of the 2013 Synthesis of the National Climate Assessment (NCA)

2011-present: Field Editor, Epidemiology, International Journal of Biometeorology

2009-present: Chair, Committee on Global Climate Change & Health, American Public Health Association's Environment Section

EMPLOYMENT HISTORY

2001-2005 Mailman School of Public Health, Columbia University
Post-Doctoral/Doctoral Research Associate
Analyzed health impacts of climate change for the New York Climate and Health Project, multi-disciplinary program linking climate, air quality, and land use change modeling projections.

1998-2001 Queens College/CUNY, Center for the Biology of Natural Systems (CBNS)
Medical Screening Coordinator
Designed/coordinated clinical studies, administration, reporting, and recruitment for the Worker Health Protection Program, medical screening offered to thousands of nuclear weapons workers.

1996-1998 Beth Israel Medical Center, New York, NY
Project Manager
Coordinated CDC study of occupational injuries and illnesses among health care workers.

1996-1997	Office of the New York City Public Advocate, New York, NY **Researcher and co-author** (with S Mattei), *Unhealthy Closure: The Need for a Full Environmental Impact Statement on the Department of Sanitation's Long-Term Plan to Control Pollution from Fresh Kills.*
Sept.1994- Sept. 1996	Radioactive Waste Management Associates, Inc., New York, NY **Research Associate** Provided expertise as geologist and health scientist on reviews of environmental impact statements for radioactive waste disposal and decommissioning projects across the US & Canada.
June 1992- Sept.1994	Natural Resources Defense Council, New York, NY **Environmental Consultant** Researched and wrote a critique of EPA's methods for assessing risks from chemical exposures.
June 1992- Aug. 1992	Los Alamos National Laboratory, Los Alamos, NM **Research Assistant** Provided support on environmental and regulatory reviews of hazardous/radioactive waste issues.
Mar. 1978- May 1979	Colorado State Geological Survey, Denver, CO **Field Geologist** Collected and analyzed samples & conducted field surveys of uranium deposits at former mine sites.

TEACHING EXPERIENCE

2008- present	**Mentor** to Columbia University Earth Institute students on Research Projects on climate change impacts and adaptation in the New York City region, as part of an innovative Climate Change Adaptation Initiative.
2005- present	**Lecturer** on Global Warming and Health, Environmental Health Sciences Core Course, Mailman SPH, Columbia University, New York, NY; as well as at Yale University, New York University, The New School for Social Research, Rutgers University, and the University of California at San Francisco Medical School.
Fall 2006	**Mellon Teaching Fellow**, Barnard College, New York NY: Co-Instructor, "Ecotoxicology;" **Doctoral Seminar Instructor**, The Earth Institute, Columbia University, New York, NY: Public Health Seminar Leader, "Environmental Science for Sustainable Development;" **Mentor** to Barnard undergraduates on their Senior Thesis research projects
Spring 2006- 2007	**Instructor**, Mailman SPH, Columbia University, "Public Health Impacts of Climate Change;" Designed and co-taught with Dr. Patrick L. Kinney a new course offering in the Department of Environmental Health Sciences, which received a Dean's Commendation for Excellence in Teaching; and became the foundation of what has developed into Mailman's new ground-breaking Master's Program in Climate Change & Public Health, lead by Dr. Kinney.
2004- present	**Mentor** to undergraduate research interns who assist on NOAA-funded research.

Fall 2003 **Teaching Assistant**, Mailman SPH, Columbia University, "Topics in Environmental Health Science;" Co-designed and conducted masters seminars in conjunction with Prof. Kinney on climate change and health (*piloted ideas that are now being applied in Spring 2006 course*)

Fall 2002 **Teaching Assistant**, Mailman SPH, Columbia University, "Air Pollution;" helped introduce masters students to concepts of atmospheric structure, air pollution sources, regulation, and health effects

ACADEMIC RESEARCH AND TRAINING

2006-2007 "Profiling Carbon Dioxide, Pollen Concentrations and Asthma in the New York City Region," as a 2006-2007 APERG Scholar in the Mid-Atlantic States Section of the Air and Waste Management Association (MASS-A&WMA) Air Pollution Educational Research Grant Program (APERG); *Objectives:* to investigate relationships between the timing and length of spring tree pollen seasons and hospital admissions for respiratory illnesses, and to survey spatial and temporal variations in carbon dioxide across the NY metropolitan region

2006-2007 Research investigating differences in greenhouse gas emissions from four different household types, defined by income and urban versus non-urban location

2004-2007 "Climate Variability, Air Quality and Human Health: Measuring Regional Vulnerability for Improved Decision-Making," funded by National Oceanic and Atmospheric Administration (NOAA); *Objectives*: Assess the degree to which weather and air pollution act independently and/or jointly in contributing to health effects, and to develop and analyze highly resolved exposure and health maps over the state of New York for 1988-2002

2001-2005 "The New York Climate and Health Project: Modeling Heat and Air Quality Impacts of Changing Land Uses and Climate," funded by US Environmental Protection Agency (EPA); *Objectives*: Develop an integrated modeling framework to assess regional climate and air quality under alternative scenarios of global climate change and regional land use change, and corresponding human health risks.

March 26-April 2 2006 DISsertations Initiative for advancement of Climate-Change ReSearch (DISCCRS) Pacific Asilomar, CA
Funded by the National Science Foundation (NSF) to meet challenges in building Successful interdisciplinary careers among recent PhD graduates in climate change impacts. One of 36 fellows selected from doctoral programs throughout the world.

July 2004 NCAR Summer Colloquium on Climate and Health, Boulder, CO (July 2004). Participated in the first summer colloquium on climate and health, held by the Advanced Study Program and Environmental and Societal Impacts Group, National Center for Atmospheric Research.

EDUCATION

October 2005 **Doctor of Public Health, Environmental Health Science**
Mailman School of Public Health, Columbia University, New York, NY

Dissertation: "Mortality in Metropolitan New York Under a Changing Climate"

Projections of future climate changes have often been made at the continental scale, yet more finely resolved projections are needed at regional scales in order for local health impacts and adaptive planning options to be evaluated. To meet these needs, a regional health risk assessment was applied to a dynamically downscaled global-to-regional model system for the tri-state New York metropolitan region. The objective was to project climate-related changes in summer heat stress and ground-level ozone concentrations and their impacts on acute mortality from all internal causes, including respiratory and cardiovascular illnesses.

The health risk assessment used model simulations of future temperature conditions and ozone concentrations developed by the New York Climate and Health Project (NYCHP). In the NYCHP model system, the NASA-Goddard Institute for Space Studies (GISS) general circulation model at 4x5° resolution was linked to the Penn State/NCAR Mesoscale Model 5 (MM5) at 36 kilometer (km) resolution to simulate future daily temperatures. The Community Multiscale Air Quality (CMAQ) atmospheric chemistry model at 36 km horizontal grid resolution was linked to the GISS/MM5 model system to simulate future daily ozone concentrations, in five summers of selected future decades across the 31-county New York metro study area. Concentration-response functions from the epidemiological literature were applied to project relative risk of heat- and ozone-related mortality in New York City in each decade. To isolate the effects of climate change on mortality, population was held constant at Census 2000 levels.

Results under the Intergovernmental Panel on Climate Change (IPCC) A2 (relatively fast-growth) scenario assumptions show that summer heat-related mortality could increase 36% by the 2020s, nearly double (95% increase) by the 2050s, and more than triple (250% increase) by the 2080s as compared to the 1990s. There is a median 4.5% increase in ozone-related acute mortality projected across the 31 counties by the 2050s. Synthesizing the heat and ozone results, for a typical summer in the 2050s, projections of additional overall mortality attributable to climate changes are 96% heat- and 4% ozone-related. The downscaled regional projections revealed heterogeneities in the temperature and ozone simulations: relatively dense population areas tend to coincide with relatively high temperatures, and relatively lower population density with relatively high ozone.

A time series analysis of daily summer mortality from 1990-1999 investigated the independent and joint effects of heat and ozone, and whether the relative risk of heat- and ozone-related mortality among urban populations exceeded that of non-urban. Poisson regression modeled daily death counts as a function of same-daily mean temperature and 1-hour daily maximum ozone concentrations averaged over the same and previous day, adjusting for day of week effects and periodic cycles. Results suggest that the heat effect (RR 1.037 per 10°F; 95% C.I. 1.028, 1.047) is less robust than ozone (RR 1.058 per 100 ppb; 95% CI 1.032, 1.085). There is a significant difference in heat-related mortality risk in urban (RR 1.062; 95% CI 1.048, 1.075) vs. non-urban (RR 1.017; 95% CI 1.006, 1.029) counties, but this is not the case for ozone. This type of health risk assessment modeling could be a useful tool for application in other metropolitan areas to evaluate the relative effects of direct (heat) and indirect (ozone) climate-health impacts that are possible under a changing climate.

June 1993	**Master of Science, Environmental & Occupational Health Science** Hunter College, City University of New York, New York, NY
January 1978	**Bachelor of Arts, Geological Sciences** Cornell University, Ithaca, NY

AWARDS

2006-2007	Air Pollution Educational and Research Grant (APERG) Scholarship Program Award recipient, to support research on the relationships between the timing and length of spring tree pollen seasons and hospital admissions for respiratory illnesses, and to survey spatial and temporal variations in carbon dioxide across the NY metropolitan region

2006 Awarded Doctoral Degree with Distinction; I.B.Weinstein Award for Academic Excellence

1993 George H. Kupchik Award, Outstanding Environmental Health Graduate; NIOSH Scholarship Recipient

1973 High School Class Valedictorian; Bausch and Lomb Science Award; NY State Regents Scholarship Recipient

JOURNAL PUBLICATIONS

As lead author:

Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon GM. 2011. Six Climate Change–Related Events In The United States Accounted For About $14 Billion In Lost Lives And Health Costs. Health Affairs 30(11):2167-2176 (Nov. 2011).

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. 2009. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. *Environmental Health Perspectives* 117:61-67 (January 2009).

Knowlton K, Rotkin-Ellman M, King G, et al. 2009. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. *Epidemiology* 19(6):S323(Nov. 2008).

Knowlton K, Lynn BH, Goldberg R, Rosenzweig C, Hogrefe C, Rosenthal J, Kinney PL. 2007. Projecting heat-related mortality impacts under a changing climate in the New York City region. *American Journal of Public Health* 97:2028-2034.

Knowlton K, Rosenthal JE, Hogrefe C, Lynn B, Gaffin S, Goldberg R, Rosenzweig C, Civerolo K, Ku J-Y, Kinney PL. 2004a. Assessing ozone-related health impacts under a changing climate. *Environmental Health Perspectives* 112: 1557-1563.

Knowlton K, Rosenzweig C, Goldberg R, Lynn B, Gaffin S, Hogrefe C, Civerolo K, Ku J-Y, Solecki W, Small C, Oliveri C, Cox J, Rosenthal J, Kinney PL. 2004b. Evaluating global climate change impacts on local health across a diverse urban region. *Epidemiology* 15 (4): S100-S100 (July 2004).

Knowlton K. 2001. Urban history, urban health. *American Journal of Public Health* 91(12):1944-1946.

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As co-author:

Bell, M.L., Goldberg R., Hogrefe, C., Kinney, P.L., Knowlton K., Lynn B., Rosenthal J., Rosenzweig C., and Patz J. 2007. Climate change, ambient ozone, and health in 50 U.S. cities. *Climatic Change* 82:61-76.

Chavarria G, Knowlton K, Atchley D. 2010. The human-climate-wildlife nexus. *Bulletin of the Atomic Scientists* (January/February 2010):48-56 (DOI: 10.2968/066001007).

Civerolo KL, Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Rosenthal J, Knowlton K, and Kinney PL. 2008. Simulated effects of climate change on summertime nitrogen deposition in the eastern US. *Atmospheric Environment* 42(9):2074-2082.

Civerolo KL, Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Rosenthal J, Knowlton K, and Kinney PL. 2007. Estimating the effects of increased urbanization on surface meteorology and ozone concentrations in the New York City metropolitan region. *Atmospheric Environment* 41(9):1803-1818 (Mar 2007).

Hogrefe C. S., B. Lynn, K. Civerolo, J.-Y. Ku, J. Rosenthal, C. Rosenzweig, R. Goldberg, S. Gaffin, K. Knowlton, and P.L. Kinney. 2004. Simulating changes in regional air pollution over the eastern United States due to changes in global and regional climate and emissions. *J Geophysical Res - Atmospheres* 109:D22301 (Nov 17 2004).

Hogrefe C, Rosenzweig C, Kinney P, Rosenthal J, Knowlton K, Lynn B, Patz J, Bell ML. 2004. Health impacts from climate-change induced changes in ozone levels in 85 United States cities. *Epidemiology* 15(4): S94-S95 (July 2004).

Kinney PL, K Knowlton, C Hogrefe, et al. 2007. Melding measurements and models to enrich the study of climate, air quality, and health. *Epidemiology* 18(5):S131(Sept 2007).

Kinney PL, Bell M, Hogrefe C, K Knowlton, et al. 2007. Climate change, air quality, and health: Assessing potential impacts over the eastern US. Epidemiology 18(5):S133(Sept 2007).

Patz JA, Kinney PL, Bell M, Ellis H, Goldberg R, Hogrefe C, Khoury S, Knowlton K, Rosenthal J, Rosenzweig C, Ziska L. 2004. *Heat Advisory: How Global Warming Causes More Bad Air Days*. NY: Natural Resources Defense Council.

Rosenthal JK, Sclar ED, Kinney PL, Knowlton K, Craudereef R, Brandt-Rauf PW. 2007. The links between the built environment, climate and population health: interdisciplinary environmental change research in New York City. *Ann Acad Med Singapore* 97(11):2028-2034.

Sheffield PE, Knowlton K, Kinney PL. 2011. Modeling of regional climate change effects on ground-level ozone and childhood asthma. *American Journal of Preventive Medicine* 41(3):251-257.

Ziska LH, Knowlton K, Rogers CA, Dalan D, Tierney N, Elder MA, et al. 2011. Recent warming by latitude associated with increased length of ragweed pollen season in central North America. *PNAS* 108(10):4248-4251 (March 8, 2011).

BOOK CHAPTERS

As lead author:

Knowlton K. February 10 2011. Globalization and Environmental Health. In: Nriagu JO (ed.) *Encyclopedia of Environmental Health*, vol.2, pp.995-1001. Burlington: Elseveier.

Knowlton K. April 2010 webinar presentation on "Climate Change, Vulnerable Populations and Adaptation" - Chapter 5 on Public Health Adaptation Strategy in CDC/APHA printed guidebook, *Climate Change: Mastering the Public Health Role* (in print April 2011).

Knowlton K, Hogrefe C, Lynn B, Rosenzweig C, Rosenthal J, Kinney PL. 2008. Impacts of heat and ozone on mortality risk in the New York City Metropolitan Region under a changing climate. *In:* Climate Information for the Health Sector. Advances in Global Change Research (Thomson M, Garcia Herrera R, eds.).

Hogrefe C, Ku J-Y, Civerolo K, Lynn B, Werth D, Avissar R, Rosenzweig C, Goldberg R, Small C, Solecki WD, Gaffin S, Holloway T, Rosenthal J, Knowlton K, and Kinney PL. 2004. Modeling the impact of global climate and regional land use change on regional climate and air quality over the northeastern United States. *In:* Air Pollution Modeling and Its Application XVI (Borrego C, Incecik S, eds.). New York: Kluwer Academic/Plenum, pp.135-144.

As co-author:

Kinney PL, Rosenthal JE, Rosenzweig C, Hogrefe C, Solecki W, Knowlton K, Small C, Lynn B, Civerolo K, Ku J-Y, Goldberg R, Oliveri C. 2006. "Assessing Potential Public Health Impacts of Changing Climate and Land Use: The New York Climate and Health Project." *In:* Regional Climate Change and Variability: Impacts and Responses (Ruth M, Donaghy K, Kirshen P, eds.). Cheltenham, UK and Northampton, MA: Edward Elgar, pp.161-189.

Rotkin-Ellman M, Knowlton K, Apatira L, Solomon G. 2011. "Lessons from the Past and Needs for the Future: Place-Based Case Studies of Vulnerability to Climate Change" (book chapter; in press).

Lead author of NRDC Briefing Papers & Fact Sheets on a variety of climate-health topics, including climate change's effects on ground-level ozone smog; pollen, allergies and asthma; heat waves; infectious diseases; harmful algal blooms; and strategies to help prepare to meet these health challenges; available online at: www.nrdc.org/health/globalwarming (2007-present).

PRESENTATIONS

Organizer & Moderator of Sessions on Climate Change and Health, Adaptation in Vulnerable Communities, and Indicators of Vulnerability and Resilience; for the 2011 and 2010 American Public Health Association Annual Meetings.

Organizer & Moderator of Symposia on Climate Change and Health at the 2009 and 2008 American Association for the Advancement of Sciences (AAAS) Annual Meetings.

As presenter:

Session on Climate Change, Air Pollution, and Adaptation in Vulnerable Communities; for the 2010 American Public Health Association Annual Meeting, Denver, Colorado, USA (November 2010).

Capitol Hill Oceans Week, Invited Speaker at Panel on the "Health Impacts of Today's Energy Choices," June 9, 2010, Washington, D.C.

Workshop on Modeling and Mitigation of the Impacts of Extreme Weather Events to Human Health Risks, Rutgers University, June 3, 2010 (Invited Speaker on Heat Wave morbidity, response, adaptation)

International Research Institute for Climate and Society, May 2010 and 2009, Columbia University, New York, NY, Invited Lecturer at Summer Symposium on Climate and Health.

National Environmental Public Health Conference, "Vulnerable Communities & Climate Change: Air Pollution in Metro NY" Centers for Disease Control & Prevention, Atlanta GA, October 26, 2009

National Center for Atmospheric Research Summer Symposium on Climate and Health, Invited Lecturer, July 2009.

American Museum of Natural History, New York, NY, April 2, 2009, "Exploring the Dynamic Relationship Between Health and the Environment" (poster presentation on dengue fever and climate change)

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. 2008. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. Oral presentation at ISEE/ISEA Joint Meeting, Pasadena, CA, October 15, 2008.

Knowlton K, Kinney PL, Bell ML, Hogrefe C, Rosenzweig C. 2005. Assessing potential health impacts of ozone and $PM_{2.5}$ under a changing climate. Poster P-AQ1.8, US Climate Change Science Program (CCSP) Workshop: Climate Science in Support of Decision Making, November 14-16, 2005, Arlington VA.

Knowlton K, Rosenthal J, Rosenzweig C, Goldberg R, Lynn BH, Gaffin S, Solecki WD, Oliveri C, Cox J, Small C, Hogrefe C, Clverolo K, Ku J-Y, Kinney PL. 2004. Projecting the local impacts of global climate change on public health in New York City. American Public Health Association Annual Meeting, November 6-10, Washington, DC.

Knowlton K, Rosenzweig C, Goldberg R, et al. 2004. Evaluating global climate change impacts on local health across a diverse urban region (poster). ISEE/ISEA Mtg, 1-4 August, New York.

Knowlton K and Rosenthal J. 2004. The New York Climate & Health Project: Global and local environmental change and public health. The New York Academy of Sciences, Environment Section (10 May 2004).

Knowlton K (invited speaker). 6 Mar 2004. "Projecting Local Impacts of Global Climate Change." Long Island Univ Annual Biology Conference: The Scientific, Biological, Social, and Economic Impacts of Fossil Fuels. Brooklyn, NY.

Knowlton K, Rosenthal J, Lynn B, Gaffin S, Kinney P, Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Rosenzweig C, Goldberg R. 2003. Assessing Public Health Impacts of Heat and Air Quality Under a Changing Climate in the NYC Metropolitan Area. Amer Geophysical Union Fall Mtg, 8-12 December, San Francisco. Eos Trans. AGU, 84(46), Fall Meet. Suppl., Abstract U32A-0028.

Knowlton K, Rosenthal JE, Gaffin S, Rosenzweig C, Goldberg R, Lynn B, Kinney PL. Modeling Public Health Impacts of Climate Change in the New York Metropolitan Region. Fifth International Conference on Urban Climate (ICUC-5), 1-5 September 2003, Lodz, Poland.

As co-author:

Civerolo K, Biswas J, Hogrefe C, Rosenthal J, Knowlton K, Lynn B, Ku J-Y, Goldberg R, Rosenzweig C, Kinney PL. 2004. Modeling Future Climate and Air Quality in the New York City Metropolitan Area, Presented at the Symposium on Planning, Nowcasting, and Forecasting in the Urban Zone, 84th AMS Annual Meeting, Jan. 11-15, Seattle, WA.

Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Civerolo K, Ku J-Y, Rosenthal R, Knowlton K, Kinney PL. 2005. Utilizing CMAQ Process Analysis to Understand the Impacts of Climate Change on Ozone and Particulate Matter. Models-3 Users' Workshop, September 26-28, Chapel Hill, NC. Online: http://www.cmascenter.org/html/2005_conference/abstracts/3_2.pdf.

Hogrefe C, Knowlton K, Goldberg R, Rosenthal J, Rosenzweig C, Lynn BH, Kinney PL. 2005. Integrating observations and MM5/CMAQ predictions to study the link between climate variability, air quality and health in New York State: Project description and initial results. Presented at the NOAA/EPA Golden Jubilee Symposium on Air Quality Modeling and Its Applications, September 20-21, Research Triangle Park, NC.

Hogrefe C, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Solecki WD, Small C, Gaffin S, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2004. Air quality in future decades – determining the relative impacts of changes in climate, anthropogenic and biogenic emissions, global atmospheric composition, and regional land use. Preprints of the 27th NATO/CCMS International Technical Meeting on Air Pollution Modeling and Its Applications, October 25 - 29, Banff, Canada, pp. 158-165.

Hogrefe C, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Solecki WD, Small C, Gaffin S, Goldberg R, Rosenzweig C, Kinney PL. 2004. Modeling the Air Quality Impacts of Climate and Land Use Change in the New York City Metropolitan Area. Models-3 Users' Workshop, October 18-20, Research Triangle Park, NC. Online:

http://www.cmascenter.org/html/2004_workshop/abstracts/Climate%20Multiscale/Hogrefe_abstract.pdf.

Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2003. Climate change and ozone air quality over the eastern United States: A modeling study. Fall Meeting 2003, San Francisco, CA, December 8-12. Eos Trans. AGU, 84(46), Fall Meet. Suppl., Abstract U32A-0027.

Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2003. Climate change and ozone air quality: applications of a coupled GCM/MM5/CMAQ modeling system. Proceedings of the 2nd Models-3 Users' Workshop, October 27-29, Research Triangle Park, NC. Online at: http://www.cmascenter.org/2003_workshop/presentations/session2/hogrefe_abstract.pdf.

Kinney PL, Hogrefe C, Lynn BH, Rosenzweig C, Rosenthal J, Knowlton K. 2005. Independent and joint impacts of heat and ozone mortality risk under a changing climate. Wengen Tenth Annual Workshop on Global Change Research, September 12-14, Wengen, Switzerland.

Kinney P, Knowlton K, Rosenthal J, Rosenzweig C, Solecki WD, Hogrefe C, Lynn B, Avissar R. 2003. Heat Stress Modeling in the NYC Metropolitan Area: Estimates for the 2050s Using a Linked Global-Regional Climate Modeling System. 2003 Open Mtg: Human Dimensions of Global Environmental Change, Montreal, Canada, October 16-18.

Rosenthal JR, Kinney PL, Knowlton K. 2004. Reshaping the built environment to reduce public health impacts of the urban heat island effect. American Public Health Association Annual Meeting, November 6-10, Washington, DC.

OTHER OUTREACH, ADVOCACY, MEDIA COVERAGE

Developed NRDC webpages on *Climate-Health Vulnerability* (www.nrdc.org/climatemaps) and *2011 Extreme Weather* (www.nrdc.org/extremeweather)

December 2011 invited presentation on Climate Change, Aeroallergens and Health to the Northern Central Weed Science Society, Milwaukee, WI

2011: Webinars on Climate Change and Health for National Nurses groups for continuing medical education credits; for Faith Community Leadership groups

Nov 2011 presentation at NJ Climate Change Adaptation Workshop at Rutgers University

Oct.29-Nov.3, 2011: presentations at the American Public Health Association Annual Mtg, Washington, DC on communicating climate-health vulnerability; and organizer of two panels, including a Special Session on "Climate Change & Health: The Global Challenge"

Sept 24-25, 2011: invited presentation at workshop on health, economics, and climate change, Boston, MA

May 26-27, 2011: International Research Institute for Climate Change, Columbia University, NY, NY – Climate Change & Health presentations and trainings for international experts and researchers

March 28-20, 2011: Indo-US Heat Vulnerability Workshop, Ahmedabad, India

Invited speaker, April 2010, Barnard College panel with Dr. Mary Robinson on climate change, NYC.

January 2010 Lecture on the health impacts of global warming as part of the *Cambridge Forum* lecture series - one of public radio's longest running public affairs programs heard on NPR stations across the US - titled, "After Copenhagen," online at: http://forum-network.org/lecture/health-impacts-global-warming.

Speaking about the impacts of changing climate conditions on infectious diseases like dengue fever in a segment titled, "Outbreak" on *Planet Green* television, October 2009.

Testimony to NYC Council on climate change, infrastructure adaptation and health, May 2008.

CARE International Executive Committee Meeting, New York, NY: *Developing Responses to the Climate Crisis* (7 June 2007).

Testimony to New York City Council (Environment Committee) on climate research findings in support of proposed Local Law No.661 to limit greenhouse gas emissions in NYC (June 2006, June 2005).

The New York Times. Worked with journalists to clarify research issues: "Forecast for New York this century: Hotter and wetter" (*New York Times*, Metro Section, 27 June 2004); "Climate scientists zoom in on changes" (*New York Times*, Metro Section, 9 December 2003).

National Public Radio. "Degrees of Concern: Climate Change and New York City," K Knowlton on West Nile virus and climate variability, broadcast interview on *Living on Earth*, nationally syndicated NPR show, 11 October 2003.

The American Museum of Natural History, Dartmouth College, The 92nd Street Y (NYC), *Science News*, *Greenwire*, *New York Daily News*, *The Poughkeepsie Journal* and *Downtown Express*.

OTHER PROFESSIONAL ORGANIZATIONAL AFFILIATIONS

American Association for the Advancement of Science; American Academy of Allergy, Asthma and Immunology; American Geophysical Union; American Meteorological Society; New York Academy of Sciences; International Society for Environmental Epidemiology.

1/11/2012

GINA M. SOLOMON M.D., M.P.H.

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EMPLOYMENT

Senior Scientist, ***Natural Resources Defense Council, 1996 - present***
Conduct research and investigation into priority environmental hazards with a focus on threats to children's health. Advocate for policy changes to improve laws and regulations to protect health. Represent NRDC in the press, legislative and agency hearings, and public fora. Supervise 7 full-time staff and numerous interns and students. Raise and manage an annual budget of over $800,000.

Director, UCSF Occupational and Environmental Medicine Residency Program, ***2008-present***
Manage all aspects of the physician training program in occupational and environmental medicine at UCSF, including directing the interview and selection process, shaping the educational requirements, managing the budget, and maintaining funding and accreditation. Supervise an associate director, program coordinator, and 4-7 residents and fellows.

Health Sciences Clinical Professor, ***University of California San Francisco, 2011 – present***
Precept occupational and environmental medicine (OEM) residents and fellows in clinic. Teach at journal club, case conference, grand rounds, and summer didactics. Teach Epi 170.16 Environment and Health course for medical and nursing students. Supervise residents from four medical centers for month-long rotations at NRDC.

Associate Director, Pediatric Environmental Health Specialty Unit, ***University of California San Francisco, 2003 - Present***

Associate Clinical Professor of Medicine, ***University of California San Francisco, 2006 –2011***

Assistant Clinical Professor of Medicine, ***University of California San Francisco, 1998 - 2006***

Clinical Instructor in Medicine, ***University of California San Francisco, 1996 - 1998***

Consultant, Ergonomics Evaluation Project, ***Massachusetts Division of Industrial Accidents, 1996 - 1997***

Fellow, Occupational and Environmental Medicine, ***Harvard School of Public Health, 1996***

Clinical Instructor in Medicine, ***Harvard University School of Medicine, 1991 - 1995***

Resident, Primary Care Internal Medicine, ***Mount Auburn Hospital, 1991 - 1995***

Research Assistant in Environmental Medicine, ***Institute of Medicine, Washington DC, 1994***

PROFESSIONAL ACTIVITIES

Science Advisory Board, *U.S. Environmental Protection Agency, 2011-2014*

Editorial Board, *Environmental Health Perspectives, 2010 – present*

Scientific Guidance Panel, *California Environmental Contaminant Biomonitoring Program, 2007-present*

Tracking Implementation Advisory Group, *California Department of Public Health, 2006 - present*

Board of Directors, *San Francisco Bay Area Physicians for Social Responsibility, 2000 – present*

Committee on Human and Environmental Exposure Science in the 21st Century, *National Research Council, 2010 – 2012*

Board of Scientific Counselors, *National Toxicology Program*, *2008 – 2011*

California Adaptation Advisory Panel, *Governor of California*, 2010

Science Advisory Board Drinking Water Committee, *U.S. Environmental Protection Agency, 2004-2010*

Science Advisory Board Acrylamide Panel, *U.S. Environmental Protection Agency, 2007 – 2008*

Reviewer, *American Academy for the Advancement of Sciences* LSDF 09-01: Innovative research programs to improve health and health care, 2009

Committee on Toxicity Testing and Assessment of Environmental Agents, *National Research Council, 2004 -2007*

Childhood Lead Poisoning Prevention Expert Advisory Committee, *California Department of Health Services, 2004 - 2006*

Scientific Advisory Group, Environmental Epidemiology and Biomonitoring, *CA Dept of Health Services Environmental Health Investigations Branch, 2000-2004*

SB702 Expert Working Group on Public Health Tracking, *California Department of Health Services, 2002 - 2004*

Science Advisory Board Trichloroethylene Panel, *U.S. Environmental Protection Agency, 2002*

Strategic Advisory Committee, *National Center for Environmental Health, CDC, 2001 - 2002*

Endocrine Disruptor Screening and Testing Advisory Committee, *U.S. Environmental Protection Agency, 1996 - 1998*

Board of Directors, *Consortium for Environmental Education in Medicine, 1998 - 2000*

Pesticides and Environmental Education for Health Providers Committee, *National Environmental Education & Training Foundation*, *1998 - 2000*

Peer Reviewer: *Journal of the American Medical Association (JAMA); American Journal of Public Health; Climatic Change; Environmental Health Perspectives; Canadian Medical Association Journal; Environmental Science and Technology; Journal of Occupational and Environmental Medicine; Environmental Research; Environmental Geochemistry and Health; Indoor Air; International Journal of Occupational and Environmental Health; Tobacco Control; European Journal of Clinical Nutrition; American Journal of Preventive Medicine; Environmental Pollution; Chemosphere; Journal of Epidemiology and Community Health.*

EDUCATION

Masters in Public Health, *Harvard School of Public Health, 1994*
Doctorate of Medicine, *Yale School of Medicine, 1991*
Bachelor of Arts, Comparative Literature, Magna cum Laude, *Brown University, 1986*

CERTIFICATION AND LICENSING

National Board of Medical Examiners, 7/92
American Board of Internal Medicine, 8/95, Recertified 5/05
American Board of Preventive Medicine, 2/98, Recertified 12/08
California Medical License number: G 083110

AWARDS AND RECOGNITION

CAAT Recognition Award, *Johns Hopkins University Center for Alternatives to Animal Testing, 2009*
Certificate of Appreciation, *Center for Community Action and Environmental Justice, 2007*
Certificate of Appreciation, *California Safe Schools, 2004*
Clean Air Award for Research, *American Lung Association of the Bay Area, 2004*
Ten Women's Health Pioneers, *The Green Guide, 2004*
Environmental Heroes Award, *The Breast Cancer Fund, 2002*
Will Solimene Award for Excellence in Medical Writing, *American Medical Writers Association, 2000*
Occupational Physicians Scholarship Fund Award, *1993, 1995*
Farr Scholarship Award, *Yale Medical School, 1988, 1989*
Phi Beta Kappa, *Rhode Island Chapter, 1986*

SCIENTIFIC PUBLICATIONS

Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon G. Six Climate Change–Related Events in the United States Accounted For About $14 Billion in Lost Lives and Health Costs. Health Affairs. 30(11): 1-10. 2011.

Rotkin-Ellman M, Wong KK, Solomon GM. Seafood Contamination after the BP Gulf Oil Spill and Risks to Vulnerable Populations: A Critique of the FDA Risk Assessment. Environ Health Perspect, 2011. http://dx.doi.org/10.1289/ehp.1103695.

Solomon G, Huddle A, Silbergeld EK, Herman J. Chapter 8. Manganese in Gasoline: Are We Repeating History? In: Clapp R (Ed.). From Critical Science to Solutions: The Best of Scientific Solutions. Baywood Publishing Inc., 2011. ISBN: 978-0-89503-404-5.

Rotkin-Ellman M, Navarro KM, Solomon GM. Gulf oil spill air quality monitoring: lessons learned to improve emergency response. Environ Sci Technol. 44(22):8365-6, 2010.

Solomon G, Janssen SJ. Health Effects of the Gulf Oil Spill. JAMA, 304(10):1118-9, 2010.

Solomon G, Janssen SJ. Communicating with Patients and the Public About Environmental Exposures and Reproductive Risk. In: Woodruff TJ, Janssen SJ, Guillette LJ, Giudice LC (eds), Environmental Impacts on Reproductive Health and Fertility. Cambridge Press, Cambridge, UK, 2010.

Rotkin-Ellman M, Solomon G, Gonzales CR, Agwaramgbo L, Mielke HW. Arsenic Contamination in New Orleans Soil: Temporal Changes Associated with Flooding. Environmental Research, 110(1):19-25, 2010.

Krewski D, Acosta D Jr, Andersen M, Anderson H, Bailar JC 3rd, Boekelheide K, Brent R, Charnley G, Cheung VG, Green S Jr, Kelsey KT, Kerkvliet NI, Li AA, McCray L, Meyer O, Patterson RD, Pennie W, Scala RA, Solomon GM, Stephens M, Yager J, Zeise L. Toxicity testing in the 21st century: a vision and a strategy. Toxicol Environ Health B Crit Rev. 13(2-4):51-138, 2010.

Solomon G, Huang A, Godsel R. Contaminants in the Air and Soil in New Orleans After the Flood: Opportunities and Limitations for Community Empowerment, In: Bullard R, Wright B (eds). Race, Place, and Environmental Justice After Hurricane Katrina. Westview Press, Boulder, CO, 2009.

Solomon G. Physicians' Duty to Be Aware of and Report Environmental Toxins. Virtual Mentor, 11(6):434-442, 2009. http://virtualmentor.ama-assn.org/2009/06/ccas2-0906.html.

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. The 2006 California Heat Wave: Impacts on Hospitalizations and Emergency Department Visits Environ Health Perspect, 117: 61-67, 2009. http://www.ehponline.org/members/2008/11594/11594.pdf.

Woodruff T, Zeise L, Axelrad D, Guyton KZ, Janssen S, Miller, M, Miller G, Schwartz J, Alexeef G, Anderson H, Birnbaum L, Bois F, Cogliano J, Crofton K, Euling SY, Foster P, Germolec D, Ginsberg G, Gray E, Hattis D, Kyle A, Leubke R, Luster M, Portier C, Rice D, Solomon G, Steinmaus C,

Vandenberg J, Zoeller T. Meeting Report: Moving Upstream: Evaluating Adverse Upstream Endpoints for Improved Risk Assessment and Decision Making. Environ Health Perspect, 116:1568–1575 (2008). http://www.ehponline.org/members/2008/11516/11516.pdf.

Humphreys EH, Janssen S, Heil A, Hiatt P, Solomon G, Miller MD. Outcomes of the California Ban on Pharmaceutical Lindane: Clinical and Ecologic Impacts. Environ Health Perspect, 116:297-302 (2008). doi:10.1289/ehp.10668.

Humphries E, Solomon G. Helping Your Patients Manage Asthma: Focus on the Source. Medscape, http://www.medscape.com/viewarticle/572573.

Solomon GM, Janssen S. Talking with patients and the public about endocrine disrupting chemicals. In: Endocrine-disrupting Chemicals: From Basic Research to Clinical Practice. Ed. Andrea C. Gore. Part of "Contemporary Endocrinology," series editor P. Michael Conn, Humana Press, Totowa, NJ, 2007.

Karr C, Solomon GM, Brock-Utne A. Health effects of common home, lawn and garden pesticides. Ped Clin N Am 54(1):63-80, 2007.

Thundiyil J, Solomon GM, Miller MD. Transgenerational exposures: Persistent chemical pollutants in the environment and breast milk. Ped Clin N Am 54(1):81-101, 2007.

Solomon GM, Hjelmroos-Koski M, Rotkin-Ellman M, Hammond K. Air quality in New Orleans, Louisiana after flooding: Mold, endotoxin, and particulate matter, October - November 2005. Environ Health Perspect 114(9):1381-1386, 2006.

Solomon GM, LaDou J, Wesseling C. Environmental Exposures and Controls, in LaDou (Ed.) Occupational and Environmental Medicine. Fourth Ed. Appleton and Lange, Stamford CT, 2006.

McDaniel P., Solomon G, Malone RE. The ethics of industry experimentation using employees: The case of taste-testing pesticide-treated tobacco. Am J Public Health 96(1):37-46, 2006.

McDaniel PA, Solomon G, Malone RE. The Tobacco Industry and Pesticide Regulations: Case Studies from Tobacco Industry Archives. Environ Health Perspect 113(12):1659-1665, 2005.

Bailey D, Solomon G. Pollution Prevention at Ports: Clearing the Air. Environ Impact Assess Review 24:749-774, 2004.

Solomon G, Humphreys E, Miller M. Asthma and the Environment: Connecting the Dots: what role do environmental exposures play in the rising prevalence and severity of asthma? Contemp Pediatrics 21(8), 2004.

Solomon GM, Hawes A, Quintero A, Widess E. Approaches to Occupational and Environmental Law in: Rosenstock L and Cullen M. (Eds.) Textbook of Clinical Occupational and Environmental Medicine, Second Edition. WB Saunders/Mosby/Churchill Livingstone, Philadelphia, 2004.

Solomon GM, LaDou J, Jackson RJ. Environmental Exposures and Controls, in LaDou (Ed.) Occupational and Environmental Medicine. Third Ed. Appleton and Lange, Stamford CT, 2003.

Solomon GM, Balmes J. Health Effects of Diesel Exhaust. Clinics in Occup & Environ Med 3:61-80, 2003.

Miller M, Solomon G. Environmental Risk Communication for the Pediatrician. Pediatrics 112:211-221, 2003.

Miller M, Solomon G. Pesticides, in: Etzel RA and Balk SJ (Eds). Handbook of Pediatric Environmental Health, Second Ed. American Academy of Pediatrics, Elk Grove Village, IL, 2003.

Solomon GM. Rare and Common Diseases in Environmental Health. San Francisco Medicine 75(9):14-16, 2002.

Solomon GM, Huddle AM. Low levels of persistent organic pollutants raise concerns for future generations. J of Epi and Commun Health. 56(11):826-827, 2002.

Solomon GM and Schettler T. Endocrine Disruption. In McCally M. (Ed.) Life Support: The Environment and Human Health. MIT Press, Cambridge MA, 2002.

Solomon GM, Weiss P. Chemical Contaminants in Breast Milk: Time Trends and Regional Variability. Environ Health Perspect 110(6): A339-A347, 2002.

Pandya RJ, Solomon GM, Kinner A, Balmes JR. Diesel Exhaust and Asthma: Potential Hypotheses and Molecular Mechanisms of Action, Environ Health Perspect 110(suppl 1):103-112, 2002.

Chaisson C, Solomon G. Children's Exposure to Toxic Chemicals – Modeling their World to Quantify the Risks. Neurotoxicology 22:563-565, 2001.

Solomon GM, Schettler T. Emerging Issues in Environmental Health: Endocrine Disruption. Canadian Med Assn Journal 163(11): 1471-1476, 2000.

Solomon GM. Hormones, Chemicals, and Public Policy. Chem and Engineering News, 78(32): 66-67, 2000.

Schettler T, Solomon GM, Valenti M, and Huddle AM. Generations at Risk: Reproductive Health and the Environment. Massachusetts Institute of Technology Press, Boston, June 1999.

Milton DK, Solomon GM, Rossiello RA, Herrick RF. Risk and Incidence of Asthma Attributable to Occupational Exposure among HMO Members. Am J Ind Med 33(1):1-10, 1998.

Solomon GM. Reproductive Toxins: A Growing Concern at Work and in the Community. J Occ Env Med 39:105-107, 1997.

Solomon GM, Huddle AM, Silbergeld EK, Herman D. Manganese in Gasoline: Are We Repeating History? New Solutions 7(2):17-25, 1997.

Frumkin H, Solomon GM. Manganese in the U.S. Gasoline Supply. Am J Ind Med 31:107-115, 1997.

Solomon GM, Morse E, Garbo M, Milton DK. Stillbirth after Occupational Exposure to N-Methyl-2-Pyrrolidone: A case report and review of the literature. J Occ Env Med 38:705-713, 1996.

Esswein E, Trout D, Hales T, Brown R, Solomon GM. Exposures and Health Effects: An Evaluation of Workers at a Sodium Azide Production Facility. Am J Ind Med 30:343-350, 1996.

Parker J, Solomon GM. Decades of Deceit: The History of Bay State Smelting. New Solutions 5:80-89, 1995.

REPORTS

Knowlton K, Solomon G, Rotkin-Ellman M. Fever Pitch: Mosquito-Borne Dengue Fever Threat Spreading in the Americas. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/dengue/files/dengue.pdf.

Rotkin-Ellman M, Solomon G. Poisons on Pets II: Toxic Chemicals in Flea and Tick Collars. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/poisonsonpets/files/poisonsonpets.pdf.

Rotkin-Ellman M, Quirindongo M, Sass J, Solomon G. Deepest Cuts: Repairing Health Monitoring Programs Slashed Under the Bush Administration. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/health/deepestcuts/deepestcuts.pdf.

Wall M, Rotkin-Ellman M, Solomon G. An Uneven Shield: The Record of Enforcement and Violations Under California's Environmental, Health and Workplace Safety Laws. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/legislation/shield/shield.pdf.

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Cohen A, Janssen S, Solomon GM. Clearing the Air: Hidden Hazards in Air Fresheners. Natural Resources Defense Council, New York, NY, 2007. http://www.nrdc.org/health/home/airfresheners/airfresheners.pdf

Solomon GM, Nance E, Janssen S, White WB, Olson E. Drinking water quality in New Orleans: June-October 2006. Natural Resources Defense Council, New York, NY, January 2007. http://www.nrdc.org/health/effects/katrinadata/water.pdf.

Solomon GM, Rotkin-Ellman M. Contaminants in New Orleans Sediment: An Analysis of EPA Data. Natural Resources Defense Council, New York, NY, February 2006. http://www.nrdc.org/health/effects/katrinadata/sedimentepa.pdf.

Solomon GM, Campbell TR, Feuer GR, Masters J, Samkian A, Paul KA. No Breathing in the Aisles: Diesel Exhaust Inside School Buses. Natural Resources Defense Council, New York, NY, 2001. http://www.nrdc.org/air/transportation/schoolbus/schoolbus.pdf.

Solomon G, Ogunseitan OA, Kirsch J. Pesticides and Human Health: A Resource for Health Care Professionals. Physicians for Social Responsibility, San Francisco, CA, 2000. http://www.psrla.org/pahk.pdf

Solomon GM, Mott L. Trouble on the Farm: Growing up with Pesticides in Agricultural Communities. Natural Resources Defense Council, New York, NY, 1998. http://www.nrdc.org/health/kids/farm/farminx.asp.

PUBLISHED ABSTRACTS

Knowlton K, Solomon G, Chavarria G. Preparing for the Health Impacts of Climate Change: Science and Societal Strategies. AAAS Annual Meeting Abstract, 2008.

Janssen S, Solomon G, Chavarria G. Measuring Human Exposures to Hormone-Disruptors: Scientific Tools for Global Health. AAAS Annual Meeting Abstract # 090-096, 2008.

Rotkin-Ellman M, Solomon G. Soil Contamination in New Orleans: Arsenic and Lead Before and After Katrina. APHA Annual Meeting Abstract #163091, 2007.

McDaniel P, Malone R, Solomon GM. The Tobacco Industry and Pesticide Regulations. Society for Research on Nicotine and Tobacco, 10th Annual Scientific Sessions, 2004.

Solomon GM. Mercury and other Persistent Fish Pollutants: Risks to the Fetus and Child. APHA Annual Meeting Abstracts, 2003

Solomon GM. Endocrine Disruptors and Current Science Policy Developments. APHA Annual Meeting Abstracts, 4185, 2000.

Solomon GM. Special Risks to Children in Agricultural Settings. Neurotoxicology, 2000.

Solomon GM, Mott L. Disproportionate Exposures and Susceptibility: Pesticide risks to farm children. Neurotoxicology 20:1, 1999.

Solomon GM, Schettler T, Huddle A, Valenti M. Endocrine Disruptors: A lens on low dose health effects. Epidemiology 9(4): S54, 1998.

Solomon GM, Huddle AM, Schettler T, Valenti M. The Tradition of Statistical Significance: An impediment to prudent public health? Epidemiology 9(4): S75, 1998.

Solomon GM. Protecting Human Health From Endocrine Disruptors: Are toxicology and risk assessment up to the challenge? APHA Annual Meeting Abstracts, 2024, 1998.

Solomon GM. The Reproductive and Developmental Effects of Organic Solvents: The dilemma of identifying a culprit. APHA Annual Meeting Abstracts, 10, 1996.

Solomon GM, Milton DK. The Occupational Asthma Incidence Study: A pilot project. APHA Annual Meeting Abstracts, 177, 1996.

Garbo M, Milton D, Morse EP, Solomon G. From DBCP to NMP: Have we progressed? APHA Annual Meeting Abstracts, 408, 1996.

SELECTED PRESENTATIONS

Congressional Testimony and Briefings:

Cancer and the Environment
Safer Chemicals Healthy Families Congressional Briefing, 4/7/11

Cancer Clusters and the Environment
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 3/29/11

Reproductive Health and the Environment
Pew Charitable Trusts Congressional Briefing, 6/11/10

Health Effects of the Gulf Oil Spill
Hearing of the House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, Washington DC, 6/10/10

Protecting Children from Environmental Threats
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 3/17/10

Endocrine Disrupting Chemicals in Drinking Water
Hearing of the House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, Washington DC, 2/25/10

Biomonitoring: A Tool for Public Health Policy
American Chemistry Society Congressional Briefing, 3/09

Health Risks to Children and Communities from Recent EPA Decisions on Air and Water Quality
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 2/07

Selected TV and Radio Appearances:

Gulf Oil Spill Health Effects
PBS Need to Know, National TV, 6/10
CBS Evening News, National TV, 6/10
CNN Evening News, National TV, 5/10
CBS The Early Show, National TV, 5/10

Cancer Cluster in Fort Chipewyan, Alberta
Canadian Broadcasting Company National Radio, 5/10

Protecting Children from Toxins in the Home
Childhood Matters, KISS-FM Radio, San Francisco, CA, 7/05; 9/07

EPA's Chemical Testing Program
NPR's Living on Earth, 6/07

Protecting the Body from Heat
MarketWatch Special Report: An Investors Guide to Global Warming (Web Video), 5/07

Mold Testing in New Orleans Post-Katrina
National Public Radio, Living on Earth, 11/05
CNN News, 11/05

Diesel Exhaust Inside School Buses
National Public Radio, Science Friday, 2/01

Selected Scientific and Educational Presentations:

Children's Health and the Gulf Oil Spill
Pediatric Academic Societies Annual Meeting, 5/11

Toxicity Testing in the 21st Century
National Academy of Sciences Conference, 5/09

Biomonitoring: A Tool for Public Health Policy
UC Berkeley School of Public Health, 3/09
UCSF School of Medicine, 1/09

Preparing for Climate Change in California
UCSF Continuing Medical Education Course, 11/09
UCSF School of Medicine, 1/08, 3/09
Public Policy Institute of California, 12/08
UCLA School of Public Health, 10/07

Health Effects of Global Warming

Governor's Global Climate Summit, 9/09
Grantmakers in Health Annual Conference, 3/09
UCSF Advances in Internal Medicine Course, 5/08
California Joint Legislative Briefing, Sacramento, CA, 8/06

Health Hazards to Day Laborers
UCSF School of Medicine FCM 184, 12/08, 11/09
Clinica Martin Baro, 3/10

Taking an Environmental History
Kaiser San Francisco Internal Medicine Residents, 10/09
SFGH Internal Medicine Residents, 7/09
UCSF School of Medicine, 1/09
N245 UCSF Nursing School, 2/09
UCSF Family and Community Medicine Residents, 12/08
UCSF Integrative Medicine Course, 5/08

Pediatric Environmental Health "Toolkit" for Pediatricians
San Francisco General Hospital Pediatric Grand Rounds, 10/07
Stanford Lucile Packard Children's Hospital Grand Rounds, Palo Alto, Ca, 4/07
Oakland Children's Hospital, Oakland, CA, 5/07
O'Connor Hospital Combined Grand Rounds, San Jose, CA, 4/07
Kaiser Santa Teresa Hospital, San Jose, CA, 6/07
Kaiser Oakland, Oakland, CA, 10/06

Cancer and the Environment
Institute for Functional Medicine Annual Meeting Plenary Address, 5/10
Northern California Cancer Center, 3/08, 10/08
UCLA Ted Mann Family Resource Center Insights Into Cancer Lecture, Los Angeles, CA, 3/07

Mold Contamination in New Orleans Post-Katrina
UC Irvine Medicine Grand Rounds, 12/07
Stanford Law School, 10/07
CDC National Environmental Public Health Conference, Atlanta, GA, 12/06

Healthy Food in Healthcare
Stanford Medical School, Palo Alto, CA, 10/05, 10/06, 11/09
UCSF Medical Center, San Francisco, CA, 3/06 & 5/06
CleanMed National Conference, Seattle, WA, 4/06
John Muir Medical Center Combined Grand Rounds, Walnut Creek, CA, 3/06

Endocrine Disruptors in the Home and Community
Heinz Conference on Women and the Environment, Boston, MA, 10/06

Controlling Environmental Hazards in Communities of Color
National Legal Aid and Defenders Association Conference, Snowbird, UT, 6/06

Breastfeeding in a Contaminated World
March of Dimes Perinatal Conference, Chicago, IL, 3/06

Mercury and Current Fish Consumption Guidelines for Children
American Academy of Pediatrics Annual Conference, San Francisco, CA, 9/05

Why Should an Internist Care About Environmental Disease?
U.C. Davis Internal Medicine Grand Rounds, Sacramento, CA 7/10
Kaiser Permanente Medical Grand Rounds, San Francisco, CA, 4/04
UCSF Alice Hamilton Memorial Lecture Grand Rounds, San Francisco, CA, 3/04

BRIANA E. MORDICK

PROFESSIONAL EXPERIENCE

NATURAL RESOURCES DEFENSE COUNCIL *Washington, DC*
OIL & GAS SCIENCE FELLOW *September 2010 – Present*

Technical advisor on oil and gas related issues. Provides scientific expertise and analysis in support of advocacy efforts. Engages with and serves as a liaison to the scientific community.

ANADARKO PETROLEUM CORPORATION *January 2005 – September 2010*

Greater Natural Buttes Natural Gas Field, Uinta Basin, UT (June 2009 – September 2010)
Senior Geologist & Team Lead

- Geologist responsible for drilling 50+ wells and selecting 500+ new drilling locations
- Worked to develop new criteria and methods for selecting optimal well locations
- Lead a team of four co-workers who were responsible for two drilling rigs and hundreds of wells; organized and lead meetings; provided weekly updates to management; served as point of contact for extended team members

Salt Creek Field CO_2 Enhanced Oil Recovery Project, Natrona County, WY (Nov 2006 – June 2009)
Geologist II

- Described and analyzed core data to develop full field depositional model
- Analyzed well logs, core, and production data to determine flow pathways of oil and CO_2
- Assisted in construction of digital 3D geologic reservoir model used for oil and CO_2 flow simulation modeling

Ozona Natural Gas Field, Crockett County, Texas (Jan 2005 – Nov 2006)
Geologist I

- Geologist responsible for drilling 100+ natural gas wells, analyzing logs, and recommending zones to be completed for production
- Remapped subsurface geology, resulting in greater predictability of productive zones in wells
- Successfully presented underdeveloped natural gas prospect at the North American Prospect Expo (NAPE) and engaged a partner to develop these prospects

ANADARKO PETROLEUM CORPORATION *The Woodlands, Texas*
GEOSCIENCE INTERN *September 2004 - November 2004*

Evaluated the Baxter shale in active Wyoming oil and gas fields for shale-gas production potential.

EDUCATION

UNIVERSITY OF NORTH CAROLINA AT CHAPEL HILL *Chapel Hill, North Carolina*
MASTER OF SCIENCE, GEOLOGICAL SCIENCES *September 2002 – May 2005*

Thesis: Pyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California

BOSTON UNIVERSITY *Boston, Massachusetts*
BACHELOR OF ARTS, EARTH SCIENCE *September 1998 – May 2002*

Senior Thesis: Provenance of discrete ash layers from the Izu-Bonin Arc system using Laser Ablation-Inductively Coupled Plasma-Mass Spectrometry

BRIANA E. MORDICK

PUBLICATIONS

Mordick, B.E., Glazner, A.F., 2006, Clinopyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California: Contributions to Mineralogy and Petrology, v. 152, no. 1, p. 111-124.

SELECTED PRESENTATIONS

- October 19, 2010:
    - Forum: National Research Council of the National Academies, Board on Earth Sciences and Resources, Committee on Earth Resources
        - Meeting Title: "Meeting Our Nation's Natural Resource Needs: Balancing Risks and Rewards"
        - Presentation Title: "Environmental Impacts of Oil and Gas Production"
- March 11, 2011:
    - Forum: EPA Hydraulic Fracturing Study Technical Workshop
        - Meeting Title: Well Construction and Operations
        - Presentation & Abstract Title: "Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned"
- June 1, 2011:
    - Forum: Environmental Entrepreneurs Monthly TeleSalon
        - Meeting Title: "Natural Gas in the Mix: Finding the Balance"
        - Presentation Title: "Environmental Impacts of Natural Gas Production"

- September 27, 2011:
    - Forum: University of Wyoming Hydraulic Fracturing Forum
        - Meeting Title: Hydraulic Fracturing, A Wyoming Energy Forum
        - Presentation Title: Hydraulic Fracturing Best Practices: Mitigating Environmental Concerns

January 11, 2012

Attn: dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Dear Sir or Madam:

Enclosed please find the comments of Catskill Mountainkeeper, Delaware Riverkeeper Network, Earthjustice, the Natural Resources Defense Council and Riverkeeper on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Reservoirs, issued September 7, 2011, and draft regulations (Proposed Express Terms 6 NYCRR Parts 52, 190, 550-556, 560, 750.1, and 750.3), issued September 28, 2011.

Sincerely,

Wes Gillingham
Catskill Mountainkeeper

Maya van Rossum
the Delaware Riverkeeper, Delaware Riverkeeper Network

Deborah Goldberg
Earthjustice

Kate Sinding
Natural Resources Defense Council

Kate Hudson
Riverkeeper

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Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Comments Summary Report: Expert Team Review of the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations

1.0 Introduction

The Louis Berger Group, Inc. (LBG) is pleased to submit this comment report on the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program and Proposed High Volume Hydraulic Fracturing (HVHF) Regulations to the Natural Resources Defense Council (NRDC) and its partner organizations, Earthjustice, Riverkeeper, Delaware Riverkeeper Network and Catskill Mountainkeeper. This comment report serves two primary purposes: 1) to provide general comments on the RDSGEIS and proposed regulations that are not limited to specific disciplines, and 2) to summarize the discipline-specific technical comments from NRDC's expert review team. The expert review team consisted of Harvey Consulting, LLC, Dr. Tom Myers, Dr. Glenn Miller, Dr. Ralph Seiler, Dr. Susan Christopherson, Meliora Design LLC, LBG, Kevin Heatley, Dr. Kim Knowlton, Dr. Gina Solomon, and Briana Mordick. The detailed technical comments from each author/organization are provided as attachments to this summary report and referenced as appropriate throughout.[1] Table 1 provides a complete list of technical comment attachments and summarizes the major topics areas addressed in each. Resumes for the members of the expert review team are provided in Attachment 12.

2.0 General Comments

2.1 RDSGEIS Fails to Address "Other Low-Permeability Shales"

The final scope and title of the RDSGEIS included other low-permeability shales, in addition to the Marcellus shale. The RDSGEIS makes it clear that development of other shales (including the Utica shale) is not only possible in the future, but is considered likely as evidenced by the inclusion of development of other shales in the Ecology & Environment. Inc. economic impact assessment.[2]

[1] All references cited and relied upon in the attached reports are hereby incorporated by reference into these comments. Hard and/or electronic copies of all references are available upon request.
[2] See the 11/23/2011 email from Steven Russo (NYSDEC) to Deborah Goldberg (Earthjustice) explaining the assumptions used in developing the scenarios for economic impact assessment include the development of "other shales."

Table 1
Technical Attachments to the Summary Comment Report

Attachment Number	Preparer	Topics Addressed
1	Harvey Consulting, LLC	Scope of SGEIS - Marcellus Shale Only Liquid Hydrocarbon Impacts Water Protection Threshold Well Casing Requirements Permanent Wellbore Plugging &Abandonment Requirements HVHF Design and Monitoring Hydraulic Fracture Treatment Additive Limitations Drilling Mud Composition and Disposal Reserve Pit Use and Drill Cutting Disposal HVHF Flowback Surface Impoundments at Drillsite HVHF Flowback Centralized Surface Impoundments Off-Drillsite Repeat HVHF Treatment Life Cycle Air Pollution Control and Monitoring Surface Setbacks from Sensitive Receptors Naturally Occurring Radioactive Materials Hydrogen Sulfide Chemical Tank, Waste Tank and Fuel Tank Containment Corrosion and Erosion Mitigation and Integrity Monitoring Programs Well Control and Emergency Response Capability Financial Assurance Amount Seismic Data Collection
2	Tom Myers, Ph. D.	Hydrogeology and Contaminant Transport Surface Water Hydrology Groundwater Quality Monitoring Setbacks from aquifers and public water supply wells Acid Rock Drainage
3	Glenn Miller, Ph.D.	Toxicology Hydraulic Fracturing Additives Naturally Occurring Radioactive Materials Contaminants in Flowback water and produced brines Wastewater Treatment issues
4	Ralph Seiler, Ph.D.	Radon in Marcellus Shale Natural Gas Naturally Occurring Radioactive Materials
5	Susan Christopherson, Ph.D.	Socioeconomic Impacts Pace and timing of natural gas development
6	Meliora Design, LLC	Water Quality Stormwater Erosion SPDES General Permit
7	The Louis Berger Group, Inc.	Noise and Vibration Visual impacts Land use Transportation Community character Cultural resources Aquatic Ecology
8[3]	Kevin Heatley, M.EPC LEED AP	Ecosystems and Wildlife
9	Kim Knowlton, DrPH	Climate Change and Public Health
10	Gina Solomon, M.D., M.P.H	Health Impact Assessment
11	Briana Mordick	Induced Seismicity

[3] Report prepared for and provided courtesy of the Delaware Riverkeeper Network.

The RDSGEIS adds some additional baseline geologic information on the Utica shale, but the environmental impacts specific to the Utica shale have not been addressed. For example, the Utica shale is almost twice as deep as the Marcellus shale, which means wells in the Utica shale will take longer to drill, would create more noise, would require more water, and would generate more waste and truck trips than wells in the Marcellus shale.

In addition to the incomplete study of deeper depth low permeability gas reservoirs, gas reservoirs at shallower depths than the Marcellus shale were not studied at all in the RDSGEIS. These shallower low-permeability shales pose development risks greater than those associated with the Marcellus shale because they are closer to protected water resources. Furthermore, the combined and/or concurrent exploitation of low-permeability shales at multiple depths may result in cumulative impacts not addressed in the RDSGEIS. The absence of the impact analyses of exploitation of shales at depths other than the Marcellus shale renders the RDSGEIS incomplete. NYSDEC should either evaluate additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the RDSGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

For additional detailed information supporting this comment, refer to Chapter 2 of the 2011 Harvey Consulting, LLC report (Attachment 1).

2.2 RDSGEIS and Regulations Fail to Protect the Environment from Non-HVHF Gas Development

While significant gaps remain as identified throughout these comments, the proposed regulatory framework for HVHF includes a number of improvements to NYSDEC's existing regulations to protect the environment from natural gas development. However, most of these improvements apply only to wells meeting the threshold to be classified as HVHF (defined as hydraulic fracturing using greater than 300,000 gallons of water).[4] NYSDEC is using a patchwork approach to regulating HVHF by adding new requirements on top of outdated requirements. A broader reform of the oil and gas development regulations is needed to address deficiencies in the existing regulations. This will ensure that best practice approaches are required for all natural gas wells in New York, including conventional wells and hydraulic fracturing using less than 300,000 gallons of water. Examples of reforms incorporated into the RDSGEIS and/or proposed regulations for HVHF that should apply to all wells include updated well casing requirements, emergency response plans and plans addressing the mitigation of noise, visual, transportation and ecological impacts.

2.3 RDSGEIS Fails to Address Indirect and Cumulative Impacts

The RDSGEIS fails to analyze important indirect and cumulative impacts as required by the State Environmental Quality Review Act (SEQRA). One of the most glaring examples of this is the

[4] The RDSGEIS arbitrarily increased the threshold for HVHF to 300,000 gal from 80,000 gal, as evaluated in the 1992 GEIS. There is no scientific justification given for the increase, and it effectively leaves all fracturing in the range 80,000-300,000 regulated by the existing rules without NYSDEC ever having conducted an environmental review showing that they are adequate for jobs that big.

RDSGEIS's failure to analyze the impacts of the pipelines and compressor stations that would be required to support the development of HVHF.

The RDSGEIS does not analyze any of the important impacts of pipelines and compressor stations (such as additional habitat fragmentation, noise and air pollutant emissions) based on flawed reasoning that such an analysis is not required because the pipelines would be reviewed under the Public Service Commission's Article VII process. The regulatory review process for pipelines is irrelevant—SEQRA requires state and local agencies to consider indirect "growth inducing" impacts. Pipelines and compressor stations are an indirect effect of the approval of HVHF. Without the approval of HVHF, there would be no reason to construct additional pipelines. Therefore, the pipelines/compressor stations and associated impacts cannot be separated from the environmental impact analysis of the HVHF regulatory program. The separate environmental review of the pipelines is, moreover, a form of segmentation, which is not permissible under SEQRA.[5] The additional natural gas pipelines and related infrastructure could also result in cumulative impacts when their impacts are combined with the impacts of HVHF that were analyzed in the RDSGEIS. The result of these deficiencies in the RDSGEIS is that the true impacts of the approval of HVHF have not been disclosed to the public and the requisite "hard look" under SEQRA has not been taken.

Similar to the treatment of pipeline infrastructure, the RDSGEIS also fails to analyze the cumulative impacts of numerous actions related to HVHF moving forward in New York, including the following:

- **Impacts from wastewater disposal and management**. The wastewater produced during the HVHF process is highly contaminated and could impact water resources if released into groundwater or surface water. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

- **Impacts from Centralized Flowback Impoundments.** The RDSGEIS fails to analyze the impacts of centralized flowback impoundments based on statements from industry that they will not be "routinely" proposed. While site-specific SEQRA review would be required for any centralized flowback impoundment, NYSDEC should have addressed the potential for significant adverse cumulative impacts (particular air quality and water resources) arising from centralized flowback impoundments in combination with the other impacts of HVHF discussed in the RDSGEIS.

- **Impacts from seismic data collection.** Seismic data collection has the potential to create

[5] See 6 § NYCRR (617.2(ag)): "Segmentation means the division of the environmental review of an action such that various activities or stages are addressed under this Part as though they were independent, unrelated activities, needing individual determinations of significance."

habitat fragmentation through the clearing of long linear corridors, among other impacts. Seismic data collection is a reasonably foreseeable part of the development process and should have been considered as an aspect of the cumulative effects assessment in the RDSGEIS.

- **Impacts from liquid petroleum.** The development of the Marcellus shale has the potential to result in wells the encounter liquid hydrocarbons. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be proposed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. None of these impacts were considered in the RDSGEIS.

- **Impacts from land use change**. The RDSGEIS contains some information about potential economic benefits, but does not examine how increase population and employment would change land use. Changes in land use would result in greater demands on the transportation system as well as ecological impacts from new residential and commercial development (above and beyond the direct impacts of the well pad sites themselves).

Fundamentally, the RDSGEIS analyzes only certain elements of HVHF and fails to analyze all elements of the process, both individually and collectively.

2.4 Unenforceable Mitigation under the HVHF Regulatory Framework

As noted throughout the detailed technical review comments, the RDSGEIS includes numerous mitigation commitments that are not enforceable because they are not included in the proposed regulations or supplemental permit conditions.

To provide a consistent regulatory framework for industry and to protect the environment, mitigation measures that would be applied across all HVHF operations should be incorporated into the proposed regulations. Mitigation measures that are site-specific should be incorporated into the supplemental permit conditions. Mitigation measures that are suggested in the RDSGEIS itself that are unenforceable (i.e., not codified through regulatory or other mechanisms) should be acknowledged as such and reduced efficacy of mitigation due to the lack of enforcement should be analyzed and disclosed.

2.5 Setbacks

As a general matter, the setback requirements stipulated by proposed HVHF regulations are inadequate to protect public health and environmental quality. Table 2 provides a summary of the setbacks proposed in the RDSGEIS and/or regulations and the recommended revisions to the setbacks based on the expert reviews conducted for NRDC.

For example, the minimum setback according to the HVHF regulatory framework for a residence is 100-feet. This is inadequate considering the potential for blowouts to eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. Other risks to residences and schools within close proximity to HVHF operations include noise levels that damage hearing and, exposure to hazardous gases, chemicals, fuels, and explosive charges.

The potential radius of impact for explosions, fire, and other industrial hazards should be considered in the RDSGEIS and proposed HVHF regulations. For example, Fort Worth Texas uses the International Fire Code as the basis for its minimum 600' setback from shale gas drilling operations. The figure below shows how the HVHF regulations setback distance requirements are significantly shorter and thus less protective than the requirements in other locations.

Comparison of NYS Setbacks from Homes and Public Buildings to Fort Worth, Texas Setbacks

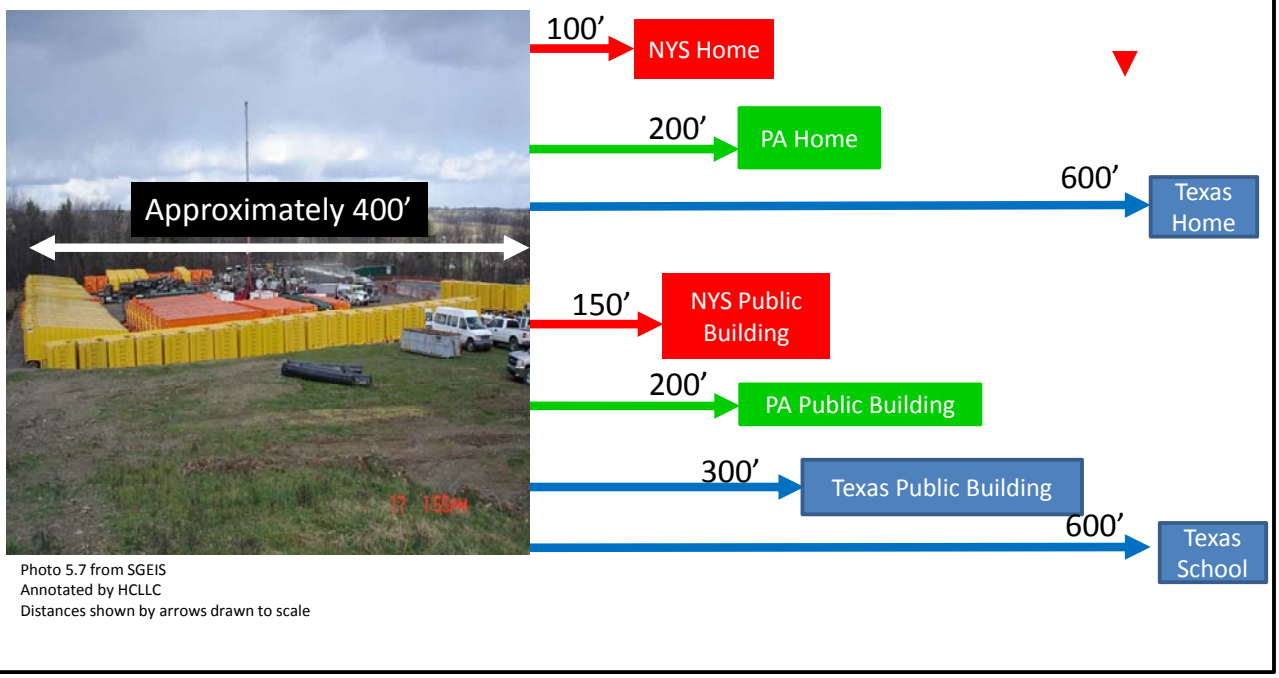


Photo 5.7 from SGEIS
Annotated by HCLLC
Distances shown by arrows drawn to scale

2.6 Insufficient Public Review of HVHF Permit Applications

The RDSGEIS fails to provide a clear and accessible process for public and local government access to site-specific HVHF activity information, while at the same time placing the burden on local government (and not the industry) to provide notice to NYSDEC that a HVHF activity may not be in compliance with local zoning or land use regulations (RDSGEIS pages 8-4 and 8-5). This essentially puts the regulatory burden on local government and at the same time fails to provide local government with access to the necessary information. The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public. NYSDEC should require public notice of the availability of HVHF permit applications locally through publication of a notice in a newspaper of general circulation and statewide through a centralized website. Permit applicants should be required to provide copies of their application to the affected municipality. The public should have immediate online access to all supporting documentation submitted with each permit application and the public review timeframe should be no less than 30 days. The regulatory framework must incorporate a mechanism for public comments on permit applications to be considered by NYSDEC before the decision to grant or reject a permit application is made.

Table 2
Summary of Setback Recommendations

	Minimum Setback under Existing/Proposed HVHF Regulatory Framework	Recommended Minimum Setback	Rationale/Notes
Residences	100 feet 6 NYCRR § 553.2	1,320 feet	Protects from noise, explosions, fire, and other industrial hazards.
Public Buildings (including schools)	150 feet 6 NYCRR § 553.2		
Primary Aquifers	500 feet 6 NYCRR § 560.4	4,000 feet	The 500 feet setback for primary aquifers should be increased to 4,000 feet (the same setback distance adopted in the RDSGEIS for Filtration Avoidance Determination watersheds), unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.
Principal Aquifers	500 feet in RDSGEIS (page 1-18) but not in the proposed regulations**	4,000 feet	The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.
Public Water Supplies	2,000 feet (6 NYCRR § 560.4)	4,000 feet	The setback for public water supplies should be the same as for principal aquifers (4,000 feet) and the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.
Private Drinking Water Wells	500 feet* (6 NYCRR § 560.4)	4,000 feet	Private and public wells should be protected to the same extent. NYSDEC should not allow the owner to waive the private well setback requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.
Stream, Storm Drain, Lake, or Pond	150 feet**	660 feet	The regulations currently contain conflicting and unclear requirements with respect to surface water resource setbacks. The regulations should be revised provide consistent setback requirements that are protective of water sources, including rivers, streams (perennial and intermittent), and lakes.
Filtration Avoidance Determination Watersheds	4,000 feet in RDSGEIS (page 7-56) but not in the proposed regulations	4,000 feet	Incorporate RDSGEIS setback commitment into regulations. In addition, the operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the FAD watershed.
Floodplains	Wellpads prohibited in the 100-year floodplain (6 NYCRR § 560.4)	Wellpads prohibited in the 500-year floodplain	For wells that might operate for 30 years, there is a 26% chance of a 100-year flood occurring during the period the well would be operated. Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.

*Setback can be waived by the landowner. The proposed regulations do not address setbacks for domestic use springs

** Setback could be waived based on site-specific analysis.

2.7 Impacts of Well Refracture Not Addressed

The assessments of environmental impacts in the RDSGEIS are all based on a single hydraulic fracturing treatment of each well. The RDSGEIS inappropriately relies on informal statements from industry that refracturing will be rare and does not quantify the number of HVHF treatments possible per well. The RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several-decade long lifecycle. The RDSGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the RDSGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts. Refer to Chapter 16 of the Harvey Consulting, LLC report (Attachment 1) for more information supporting this comment.

3.0 Summary of Technical Comments

3.1 Liquid Petroleum Impacts

The RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be needed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.

The RDSGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The RDSGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drill sites that may be required to develop oil resources identified by shale gas exploration and production activities.

The comments summarized in this section are covered in greater detail in Chapter 3 of the Harvey Consulting, LLC report (Attachment 1).

3.2 Well Casing Requirements

The comments summarized in this section are covered in greater detail in Chapters 5 through 8 of the Harvey Consulting, LLC report (Attachment 1).

3.2.1 Conductor Casing

Conductor casing is the first string of casing in a well and is installed to prevent the top of the well from caving in. The conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the proposed regulations and should

apply to all natural gas wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

3.2.2 Surface Casing

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well. Stray gas may impact groundwater and surface water from poor well construction practices. Properly constructed and operated gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion. Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania and other locations.

The RDSGEIS and proposed regulations include important improvements for surface casing that incorporate many of the comments provided by this working group in 2009. Notable improvements include requirements related to cement quality, casing quality, and installation techniques. Unfortunately, there are a number of inconsistencies between the permit conditions and the proposed regulations that create uncertainty about what will be required. The Harvey Consulting, LLC report provides recommendations for correcting these inconsistencies. Finally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.3 Intermediate Casing

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. The RDSGEIS and proposed regulations include important improvements for intermediate casing in comparison to the 2009 DSGEIS. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. However, the remaining area for improvement in the proposed regulations is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing, on which the proposed regulations are silent. There are also a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.4 Production Casing

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone or, alternatively, it is set just above the hydrocarbon zone. Production casing is used to isolate hydrocarbon zones and to contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier

that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The RDSGEIS and proposed regulations include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the proposed regulations is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and proposed regulations require production casing to be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. The proposed regulations also require the cement placement and bond be verified by well logging tools. These requirements are best practice. The Harvey Consulting, LLC report provides minor additional recommendations to improve consistency of the various requirements for production casing and highlights additional best practices that should be considered.

3.3 HVHF Design and Monitoring

Computer modeling is routinely used by industry to design hydraulic fracture treatments. During actual fracture stimulation treatments, data is collected to verify model accuracy, and the model is continually refined to improve its predictive capability. Data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability. HVHF modeling is an important way of helping to ensure fracture treatments do not extend outside the target formation. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport.

The RDSGEIS does not require well operators to develop or maintain a hydraulic fracture model. Instead, the RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned. Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. Instead, NYSDEC needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and the environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective; it is also good business because it optimizes gas production and reduces hydraulic fracture treatment cost. Best practices for HVHF design and monitoring should be included as a mitigation measure, and codified in regulations as a minimum standard. These best practices include utilizing hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone.

The comments summarized in this section are covered in greater detail in Chapter 10 of the Harvey Consulting, LLC report (Attachment 1).

3.4 Corrosion and Erosion Mitigation and Integrity Monitoring Programs

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide

(CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves. HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require that facilities be designed to resist corrosion (e.g., material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment. Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be evaluated and codified in regulations. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

The comments summarized in this section are covered in greater detail in Chapter 23 of the Harvey Consulting, LLC report (Attachment 1).

3.5 Well Control & Emergency Response Capability

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems. The addition of an Emergency Response Plan (ERP) requirement to the RDSGEIS is a substantial improvement over the 2009 DSGEIS, which failed to address this issue. However, it is recommended that NYSDEC include a review, approval, and audit processes to ensure that quality ERPs are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

The comments summarized in this section are covered in greater detail in Chapter 24 the Harvey Consulting, LLC report (Attachment 1).

3.6 Financial Assurance Amount

NYSDEC ignored comments submitted by this working group in 2009 requesting that the SGEIS examine financial assurance requirements to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination). Although changes in financial assurance amounts would require legislative action, the analysis of this issue is necessary to fully disclose the potential adverse environmental impacts that would result in the absence of adequate financial assurances. Moreover, such an analysis would be an appropriate way of bringing this need for legislation to the attention of elected officials as appropriate mitigation for identified significant adverse impacts.

The importance of reevaluating financial assurance requirements is heightened when the inadequacy of the existing requirements is considered. For wells between 2,500’ and 6,000’ in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000. For wells drilled more than 6,000’ deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based solely on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6). These requirements are

far less than those in other locations. Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well. Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS. In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas.

NYSDEC's financial assurance requirements should not narrowly focus on the costs of plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment. Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be evaluated and included in the proposed regulations.

The comments summarized in this section are covered in greater detail in Chapter 25 of the Harvey Consulting, LLC report (Attachment 1).

3.7 Hydrogeology and Contaminant Transport

The RDSGEIS dismisses the potential for groundwater contamination due to HVHF on the basis of faulty science and unsupported assumptions.

1. The characterization of the hydraulic fracturing process and effects in the RDSGEIS is technically incorrect, leading to important impacts being overlooked.

2. The RDSGEIS assumes that the geologic layers above the Marcellus shale will stop contamination of aquifers without providing sufficient information on these layers, and ignoring the potential for existing faults and fractures to expedite contaminant transport. It also ignores studies which show that hydraulic fracturing has fractured formations as much as 1500 feet above the target shale, thereby providing pathways through the rock which the RDSGEIS relies on for stopping contaminant transport.

3. The RDSGEIS impact analyses are incomplete from a spatial perspective. The analyses focus on *local* impacts and fails to address the *regional* impacts of HVHF on the characteristics of the shale and the environmental implications of these changes. Such changes include increased shale permeability to water flow, which increases the risk of aquifer contamination over time.

4. The RDSGEIS analyses are incomplete from a temporal perspective. The analyses do not address the potential long-term aquifer contamination impacts by focusing on a time period of few days, assuming contamination has not occurred in other locations that lack the monitoring that would be necessary to detect contamination, and not considering evidence of the potential vertical movement of fracking fluid to near-surface aquifers as discovered under comparable conditions elsewhere.

Detailed technical supporting information for the deficiencies noted above is provided in the report prepared by Dr. Tom Myers (Attachment 2). The Myers report also provides a number of important recommendations for:

1. Improving and expanding the characterization of the hydraulic fracturing process and impacts in the RDSGEIS; and
2. Implementing measures as part of the review of specific well site proposals to avoid significant adverse aquifer contamination impacts.

The measures should include the following:

1. Mapping groundwater gradients above the Marcellus shale using existing data.
2. Requiring seismic surveys to locate faults prior to drilling.
3. Implementation of a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport.

The groundwater monitoring at domestic wells proposed in the RDSGEIS is a scientifically improper method of monitoring the location of a contaminant plume because domestic wells are not designed for monitoring. Dedicated monitoring wells are necessary to prevent contamination of water wells by detecting contaminants before they reach the water wells.

3.8 Well Plugging and Abandonment

Wells that are not properly plugged can act as a preferential pathway for surface contaminants to impact groundwater resources. There are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned). As a result, there is a risk that improperly planned HVHF wells or fractures could intersect abandoned wells and contaminate groundwater. Key recommendations from Chapter 9 of the Harvey Consulting, LLC report (Attachment 1) related to well plugging and abandonment (P&A) include the following:

- The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

- The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

- The SGEIS requirements with respect to the plugging of improperly abandoned wells nearby proposed HVHF wells should be strengthened and incorporated in the proposed regulations.

3.9 Seismic Data Collection

Seismic surveys are used by industry to target hydrocarbon formations for exploration and appraisal drilling. Typically seismic surveys are conducted using vehicle-mounted vibrator plates that impact the ground or use explosive to create seismic waves which bounce off of subsurface rock strata and geologic formations. The reflected seismic waves are measured at various surface receivers. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (up to 20'-50' wide). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection.

The RDSGEIS does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys. If 2D or 3D seismic surveys are planned, or are possible in the future, the proposed HVHF regulations should codify a permitting process for these activities and institute mitigating measures in the RDSGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas. In addition, the increased industrial activity (e.g., economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the RDSGEIS.

The comments summarized in this section are covered in greater detail in Chapter 26 of the Harvey Consulting, LLC report (Attachment 1).

3.10 Surface Water Hydrology

The RDSGEIS has addressed many of the deficiencies of the 2009 DSGEIS with respect to the treatment of hydrology issues. As discussed in the Myers report (Attachment 2), NYSDEC proposes to use the natural flow regime method (NFRM) for all regions by means of permit conditions. However, NYSDEC should verify the accuracy for the proposed methods for estimating passby flows at ungauged sites. Since NFRM is proposed to be applied everywhere (and not just in a specific case which would justify its use as a permit condition), it would be more appropriate for NYSDEC to include the use of the NFRM as a requirement in the regulations themselves. The following changes should be accounted for in the regulatory framework regarding the avoidance or reduction of potential impacts resulting from water withdrawal:

- NYSDEC should coordinate water withdrawals among operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.
- The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.
- Passby flows should be maintained with consideration of the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating

flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.

3.11 Stormwater, Sedimentation and Erosion

All of the comments summarized in this section are covered in greater detail in the Meliora Design, LLC report (Attachment 6).

3.11.1 Cumulative Water Quality Impacts of Land Disturbance Are Not Addressed

The RDSGEIS provides only a very brief generic discussion of the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). The RDSGEIS makes no attempt to evaluate the cumulative impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the original draft of the GEIS nearly twenty years ago, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts on water quality in the most general and generic manner, with little industry specific consideration, and no consideration of total or cumulative impacts. A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential to a full environmental impact analysis, and to any determinations by NYSDEC on the appropriate regulatory permitting requirements.

3.11.2 Stream Crossing Impacts Are Not Addressed

The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft State Pollutant Discharge Elimination System (SPDES) General Permit. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current NYSDEC regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. NYSDEC should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed requirements to regulate and mitigate these impacts.

3.11.3 Mitigation and SPDES General Permit Do Not Consider Existing Water Quality

With the exception of watersheds that have received Filtration Avoidance Determinations, the RDSGEIS (and associated Draft SPDES HVHF General Permit) do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support the adequacy of the proposed setbacks to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep slopes), and the setbacks

discussed in the narrative of Chapter 7 are not clearly coordinated with EAF requirements in Appendices 4, 5, 6 and 10 and the Draft HVHF General Permit mapping and documentation requirements (and the Draft SPDES HVHF General Permit is presumably the regulatory mechanism for compliance). NYSDEC should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.

3.11.4 SPDES General Permit Flawed

The Draft SPDES General Permit for HVHF is essentially a compilation of the NYSDEC's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. It is not clear from the RDSGEIS's very limited discussion of land disturbance and surface water impacts that a general permit process is sufficient to protect water quality. It is also not clear that an industry that is not subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF. Finally, the general permit process does not provide a timeframe (or process) for public review, comment, and objection to any or all parts of proposed general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the NYSDEC and meeting minimum performance requirements. The SPDES HVHF General permit should provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site before general permit coverage is granted. The permit coverage timeline should be adjusted to provide for public comment and appeal.

3.12 Hazardous and Contaminated Materials Management

All of the comments summarized in this section are covered in greater detail in the Harvey Consulting, LLC report (Attachment 1) and the report of Dr. Glenn Miller (Attachment 3).

3.12.1 Disposal of Waste and Equipment Containing NORM

Naturally Occurring Radioactive Materials (NORM) can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **Drilling**: Drill cuttings containing NORM are circulated to the surface.
- **Completion**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **Production**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

The RDSGEIS fails to establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved relative to the 2009 DSGEIS in that it establishes radioactive limitations and testing in some cases, but testing is

still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g., for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

3.12.2 Drilling Mud Composition and Disposal

Drilling muds may contain mercury, metals, Naturally Occurring Radioactive Materials (NORM), oils and other contaminates. The NYSDEC appropriately removed the statement that "*drilling muds are not considered to be polluting fluids"* from the proposed regulations in response to this working group's 2009 comments. This positive change is commendable, but there are two problems related to the regulation of drilling muds that remain:

- The RDSGEIS states that the vertical portion of wells would be "typically" drilled using compressed air or freshwater mud as the drilling fluid. There is no regulatory restriction on industry using toxic additives in drilling mud, with corresponding increases in the risks of water resources contamination during drilling, transport and disposal. NYSDEC should stipulate in the regulations the mandatory use of compressed air or freshwater mud and prohibit the use oil-based muds, synthetic-based muds and the use of toxic additives.
- The proposed regulations do not provide criteria for acceptable drilling mud disposal plans to ensure safe handling and disposal. The proposed regulations should require specific best practices for drilling mud handling and disposal.

3.12.3 Reserve Pit Use and Drill Cuttings Disposal

The RDSGEIS acknowledges the numerous environmental advantages of a closed loop tank system to manage drilling fluids and cuttings rather than reserve pits, but fails to require a closed loop tank system in all circumstances. The closed loop tank system is only required for wells without an acceptable acid rock drainage mitigation plan for onsite disposal and for cuttings that need to be disposed at a landfill because they contain toxic additives. The proposed regulations should prohibit reserve pits and require a closed loop tank system. Reserve pits should only be allowed where the applicant demonstrates that the closed loop tank system would be technically infeasible. The proposed regulations also should include testing of the shale to determine the extent of potentially acid generating material included in the cutting.

The RDSGEIS states that onsite disposal of water-based muds is permissible, despite the fact that these muds may contain mercury, metals and other contaminates. These contaminated muds would be put in direct contact with soils and groundwater, resulting in the potential for significant adverse environmental impacts not addressed in the RDSGEIS. Some portions of the RDSGEIS and proposed regulations vaguely reference a requirement for consultation with the NYSDEC Division of Materials Management prior to disposal of cuttings from water-based mud drilling, but this "consultation" improperly circumvents the proper public review that would be provided by reaching a decision on the disposal requirements for water-based mud and associated cuttings through the environmental review process.

3.12.4 Hydraulic Fracture Additive Limitations

The RDSGEIS and proposed regulations continue to rely solely on the drilling operators to (1) regulate themselves, and (2) select the lowest toxicity chemicals for use in fracture treatment additives.

The proposed regulations require documentation that the additives exhibit "reduced aquatic toxicity" and "lower risk to water resources" compared to alternate additives or documentation that alternatives are not equally effective or feasible. There are no specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk. Operators would still be allowed to use harmful chemicals merely by stating to NYSDEC that these are the only chemicals that would be "effective" or by showing that the chemicals they propose are slightly less toxic than the most toxic alternatives.

To address this problem, the RDSGEIS and proposed regulations should identify the type, volume and concentrations of fracture treatment additives that are protective of human health and the environment; include a list of prohibited additives; and require the use of non-toxic materials to the greatest extent possible.
NYSDEC should develop the list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the New York State Department of Health (NYSDOH) has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the RDSGEIS as a mitigation measure and codified in the proposed regulations.

3.12.5 Centralized Surface Impoundments for HVHF Flowback Off-Drillsite

The 2009 DSGEIS disclosed significant adverse air quality impacts associated with centralized surface impoundments for HVHF flowback, which were found to emit over 32.5 tons of air toxics per year. However, this important impact information was removed from the RDSGEIS. Instead, NYSDEC improperly declined to analyze centralized surface impoundments based on statements by the industry that they would not "routinely propose" to use centralized flowback impoundments. The proposed regulations do not prohibit centralized surface impoundments, which would be appropriate

mitigation for the significant adverse impact identified in the 2009 DSGEIS, and instead a separate site-specific SEQRA review would be required for them.

3.12.6 Chemical and Waste Tank Secondary Containment

NYSDEC appropriately codified a requirement for secondary containment for chemical and waste handling tanks in the proposed regulations. However, the proposed regulations do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment. The regulations should be revised to address secondary containment for transport, mixing and pumping equipment in order to minimize potential soil and water resource impacts from chemical spills. There are several other minor modifications to the proposed regulations for secondary containment detailed in Chapter 21 of the Harvey Consulting, LLC report (Attachment 1) to eliminate inconsistencies between various regulatory requirements.

3.12.7 Fuel Tank Containment

NYSDEC appropriately included a requirement for fuel tank secondary containment in the Proposed Supplementary Permit Conditions. However, this requirement is confused by inconsistent statements in the RDSGEIS that secondary containment is not required for *temporary* fuel tanks (page 7-34). In addition to correcting this inconsistency, the proposed regulatory framework for fuel tank containment should be substantively improved to be more protective of the environment through adoption of the following changes:

- Define clear criteria for adequate containment (e.g., using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area).
- Include mandatory minimum setbacks from surface water features, homes and public buildings. The proposed regulations contain a setback for surface water resources, but only "to the extent practical."
- Explain how NYSDEC's requirements for fuel tank containment interface with federal requirements (40 CFR Part 112).
- Require tank inspections, spill prevention and spill alarm systems.
- Clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed in cases where secondary containment is impractical, and codify the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

3.13 Toxicology

This section addresses the toxicology-related issues associated with Naturally Occurring Radioactive Materials (NORM), hydraulic fracturing additives and waste disposal. For supporting technical information for these comments, refer to the technical reports of Dr. Glenn Miller (Attachment 3) and Dr. Ralph Seiler (Attachment 4).

3.13.1 Naturally Occurring Radioactive Materials

The Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations. The primary environmental contamination risk associated with NORM is in production brines. Appendix 13 of the RDSGEIS presented some information on radioactivity

characteristics of vertical wells in the Marcellus Shale in New York. However, the data in Appendix 13 identifies only 14-24% of the gross alpha radiation sources in the water samples. The sources of the other 75%+ of alpha radiation are not identified. The RDSGEIS explicitly acknowledges that the scientific understanding of NORM in production brine is incomplete.[6] NYSDEC should have obtained more information on the radiation sources in production brine as part of the SGEIS process because it is essential to NYSDEC's decision-making process and for NYSDEC to ensure that adequate regulations are in place before widespread HVHF occurs in New York. Even if the information could not have been reasonably obtained (which is not the case here), the proper approach for SEQRA compliance would have been to disclose the unavailable information in accordance with NYCRR §617.9 (b) (6)[7]:

One possible source of the unspecified alpha levels in production brines is polonium. Polonium-210 is 5,000 times more radioactive than radium and is highly toxic.[8] Polonium-210 is difficult and expensive to remove from drinking water and bioaccumulates in the environment. Before completing the SEQRA process, NYSDEC should determine if polonium is a significant component of alpha emission in formation waters and identify appropriate regulations that address polonium-contaminated wastewater to prevent water resource impacts. Specific technical recommendations regarding the analyses that should be conducted to determine the presence of polonium are provided in Attachment 4. Attachment 4 also addresses the potential for Polonium-210 exposure via build-up in natural gas delivery pipes.

3.13.2 Radon Exposure via Natural Gas Combustion

Radon is a cancer-causing, radioactive gas. Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. The quantity of radon in natural gas is highly variable and has not been studied by NYSDEC in the Marcellus Shale. While normal natural gas use in properly ventilated burners are unlikely to contribute to radon concentrations in a closed space, poorly vented areas may well be a problem, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners) need to be subjected to risk assessment. At the very least, substantially more radon measurements need to be made. The risk is likely to be greatest in those areas that already have elevated radon in air, and that risk may be enhanced by the natural gas contribution. Any increase in radon exposure in the Southern Tier is of particular concern in terms of cumulative impacts given that the NYSDOH estimates the majority of homes in

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[6] 2011 RDSGEIS Page 5-142: "The data indicate the need to collect additional samples of production brine to assess the need for mitigation and to require appropriate handling and treatment options…."

[7] *In addition to the analysis of significant adverse impacts required in subparagraph 617.9(b) (5) (iii) of this section, if information about reasonably foreseeable catastrophic impacts to the environment is unavailable because the cost to obtain it is exorbitant, or the means to obtain it are unknown, or there is uncertainty about its validity, and such information is essential to an agency's SEQR findings, the EIS must:*

(i) identify the nature and relevance of unavailable or uncertain information;
(ii) provide a summary of existing credible scientific evidence, if available; and
(iii) assess the likelihood of occurrence, even if the probability of occurrence is low, and the consequences of the potential impact, using theoretical approaches or research methods generally accepted in the scientific community.

This analysis would likely occur in the review of such actions as an oil supertanker port, a liquid propane gas/liquid natural gas facility, or the siting of a hazardous waste treatment facility. It does not apply in the review of such actions as shopping malls, residential subdivisions or office facilities.

[8] http://www.who.int/ionizing_radiation/pub_meet/polonium210/en/index.html

the region have existing basement radon levels above the EPA "action level" of 4 pCi/L. Between 20 and 40 percent of homes in the several Marcellus Shale counties have long-term exposure to radon levels above the EPA limit in their living areas.[9] Before completing the SEQRA process, NYSDEC should analyze the cumulative health risk posed by additional radon exposure from Marcellus Shale natural gas combustion so that appropriate mitigation measures can be identified to address the issue.

3.13.3 Hydraulic Fracturing Additives

The RDSGEIS does not present sufficient information to analyze the toxicology risks posed by hydraulic fracturing additives. It does not address the toxicology risks generically or at the site level. The proposed regulations do not require permit applicants to provide sufficient information for the risks of these additives to be considered at the site level. The RDSGEIS provides a long list of potential additives (Tables 5.4 and 5.5), but does not analyze their potential environmental impacts. The list of additives is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives nor the amounts in which they would be used during the HVHF process there is no basis for estimating the risk of these components with regard to their presence in the produced flowback or produced water.

The RDSGEIS misrepresents the presence of hydraulic fracturing additives in flowback. Table 6.1 of the RDSGEIS states that no non-naturally occurring additives were detected. However, most of these additives cannot be detected through standard methods. Table 6.1 should be revised to indicate which additives were actually capable of being detected by the analytical methods selected and the associated detection limits. This is a customary practice and standard. The proposed regulations should require testing of flowback water for acrylonitrile, a non-naturally occurring chemical that if detected provides a clear indication of off-site contamination by hydraulic fracturing.

3.13.4 Disposal of Contaminated Wastewater

The water that flows back immediately following hydraulic fracturing is heavily contaminated, primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The produced brines that are released during production generally have higher concentrations of naturally occurring contaminants than flowback waster (although lower volumes) and similarly represent a serious chemical contamination potential. Four problematic components of the flowback water and produced brines are present: the radioactive component (NORM); the inorganic salts, metals and metalloids; the organic substances (from the hydrocarbon formation) and the hydraulic fracturing additives. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS. Reuse is not a

[9] http://www.wadsworth.org/radon/

complete disposal option because residual salts and other contaminants must still be managed. Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells, municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water) and private treatment plants (of which none currently exist in New York). The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with these disposal options.

3.14 Air Quality and Odors

For supporting technical information for the comments provided in this section, refer to Chapters 17 and 20 of the Harvey Consulting, LLC report (Attachment 1).

3.14.1 Air Quality Modeling Assumptions

The air quality analysis in the RDSGEIS contains some substantial improvements compared to the DSGEIS, but the assumptions used still warrant additional review and justification. For example, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. In addition, the mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal). Limitations used in the modeling assumptions must all be translated into SGEIS mitigation measures and codified in the proposed regulations to ensure that the National Ambient Air Quality Standards will not be exceeded.

3.14.2 Air Quality Monitoring Program

The RDSGEIS includes a commitment to develop a regional air quality monitoring program to address the potential for significant adverse air quality impacts. However, more information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

3.14.3 Greenhouse Gas Emissions Mitigation Plan

The RDSGEIS took a step in the right direction with the inclusion of a requirement for greenhouse gas emissions (GHG) impact mitigation plans. However, this requirement needs to be further defined. NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions

reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions. The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs. The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.4 Flare and Venting of Gas Emissions

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. During production operations, high pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. Reducing gas flaring and venting is widely considered best practice for reducing air quality impacts of natural gas development. The RDSGEIS air quality analyses of flaring assumed it would be limited to three days based on statements from industry, even though the actual duration should be longer. Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting restrictions should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.5 Reduced Emission Completions

Reduced Emission Completions (RECs, also known as "green completions") control methane and other GHG emissions following HVHF operations. RECs also reduce nitrogen oxide (NOx) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere. The RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of wellsites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale. Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a

mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.6 Gas Dehydrators

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. Gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions. The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement. In addition to this requirement, natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.7 Diesel Engine Emissions Control

NRDC's 2009 comments recommended limiting diesel engines to Tier 2 or higher. The RDSGEIS takes a step in the right direction by prohibiting "Tier 0" engines and requiring Tier 2 engines in most cases. To further strengthen air quality protection from diesel emissions SGEIS should examine whether it is possible to eliminate Tier 1 engine use altogether.

3.14.8 Leak Detection and Control

Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs. NYSDEC's proposed Leak Detection and Repair Program should be revised to require: a drillsite Leak Detection and Repair inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the proposed regulations, and be required for all natural gas operations, not just HVHF operations.

3.14.9 Cleaner Power and Fuel Supply Options

The RDSGEIS did not examine cleaner power and fuel supply options as was requested in NRDC's 2009 comments. In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where highline power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. These requirements should apply to all natural gas operations, not just HVHF operations.

3.14.10 Hydrogen Sulfide (H_2S) ("Sour Gas") Emissions

In addition to air quality risks associated with emissions of criteria pollutants and air toxics resulting from natural gas development, additional air quality risks can occur as a result of the release of hydrogen sulfide (H_2S) or sour gas. H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause very serious health symptoms, and can be deadly at the higher concentrations found in some oil and gas wells.

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public. The RDSGEIS does not analyze H_2S impacts based on the argument (supported by limited evidence) that to date H_2S has not been detected in high concentrations in HVHF operations in Pennsylvania. However, the early experience in Pennsylvania does not mean that there is no potential for H_2S issues to develop over time in New York.

A supplemental permit condition proposed in the RDSGEIS appropriately requires monitoring for H_2S during the drilling phase. However, a requirement should be added to the HVHF regulations to ensure that periodic monitoring occurs throughout production as gas fields age and sour. H_2S monitoring requirements should apply to all wells and therefore should be addressed through regulations, rather than through permit conditions that can be altered without public review. The regulations should stipulate that when monitoring detects H_2S, nearby neighbors, local authorities and public facilities should be notified of the risk of H_2S gas. They should be provided information on safety and control measures that the operator will be required to undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

3.15 Socioeconomics

This section addresses the socioeconomic impacts of HVHF. For supporting technical information for these comments, refer to the technical report from Dr. Susan Christopherson (Attachment 5).

3.15.1 NYSDEC's Socioeconomic Impact Analysis

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. There are a number of substantive concerns raised by the discussion of socioeconomic impacts presented in the RDSGEIS and by the Economic Assessment Report (EAR) prepared by NYSDEC's consultant, Environment and Ecology, on which that discussion is based.

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used in the RDSGEIS to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a "ramp-up" period and then proceeding through a regular pattern of well development over time. This model is misleading, and because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model cannot appropriately assess those impacts.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required, along with an estimate of how costs will increase and accumulate as development expands.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur.

3.15.2 Uncertainty and Volatility of Natural Gas Production and its Socioeconomic Impacts

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the commercially extractable gas from any particular well is uncertain. This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, they may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies. The model used in the RDSGEIS to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this unlikely gradual, regular development scenario, raising doubts about the projection of economic benefits based on that model.

The spatial distribution of impacts is also uneven. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. The uncertainties in the geographic extent of drilling and the potential for intensive development in "hot spots" have implications for social and economic impacts. If drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape (as was modeled in the RDSGEIS), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic costs of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry.

Contrary to the RDSGEIS' contention that the regularized development model "does not significantly affect the socioeconomic analysis," smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies.

3.15.3 Economic Impact Study Fails to Address Costs

The 2011 RDSGEIS analyzes potential *economic benefits* of HVHF, but fails to provide the same level of analysis of the potential *costs* of HVHF. A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF.

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt.

(2) Costs to the state that will reduce or offset tax revenues are not calculated.

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the RDSGEIS, including public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., as well as costs associated with monitoring and inspection and infrastructure maintenance. Although experience in other shale gas plays demonstrates that these costs are likely, the RDSGEIS makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment.

(4) There is no analysis of the expected 2-3 year lag between immediate costs and anticipated revenues, during which communities will be faced with significant public service costs.

Given the inability of the EAR input-output model to address the costs of gas development and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

3.15.4 Impacts on Other Industries

HVHF has the potential to have significant adverse effects on the viability of other industries in New York, particularly tourism and agriculture. In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine

state investments intended to support those industries. Given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

3.15.5 Housing and Property Value Impacts

The potential impacts of HVHF on the housing supply, housing costs, and housing financing are inadequately addressed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.

The report assumes that the current housing stock would be used to house any workers who move to the production region on a "permanent" (more than one year) basis. However, given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing. This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the "boomtown" phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either or temporarily or permanently, the value of this new housing is likely to plummet. The social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed. These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% reduction in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus, "…residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights." (EAR, 4-114). The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values. A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

3.15.6 Effects on Employment

The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells.

In contrast, nearly 674,000 New York jobs were sustained by tourism activity last year, representing

7.9% of New York State employment, either directly or indirectly. New York State tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010. In the Southern Tier alone, the tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in 2008. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue.

The RDSGEIS assumes that as the industry "matures" in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals.

In addition, many of the highest paid jobs associated with HVHF will not be filled locally. Occupational employment statistics geographical analysis of petroleum engineers, one of the most common occupations in the oil and gas industry, indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. This data suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs in petroleum engineering.

The creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is also likely to occur outside the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process. Although the EAR asserts that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs.

3.15.7 Regional Plan of Development Approach to Mitigating Socioeconomic Impacts

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator's identification of inconsistencies with comprehensive land use plans. The measures are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions. Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur enables local government to anticipate and develop strategies to mitigate cumulative impacts. The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal,

pipeline construction) in the area to be affected. A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

To further assist communities in planning for socioeconomic impacts, a series of reporting requirements should be incorporated into the RDSGEIS and regulations. As development activities begin and progress, the information provided in initial projections should be confirmed or revised on a semiannual basis. This information is critical to forecasting and meeting housing and service demands.

In addition, mitigation strategies need to be developed and described in the RDSGEIS that address long term costs to affected regions and the impacts of the resource depletion phase of the exploration, drilling, and development process, when population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Finally, mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

3.16 Traffic and Transportation

While the RDSGEIS improves upon the 2009 DSGEIS regarding estimates truck trip generation, the impact of HVHF on roadway congestion and safety has not been adequately addressed in the RDSGEIS.

The impacts of a typical multi-well development on congestion and safety should be analyzed in detail; such analysis should include a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related economic activity.

The LBG technical memo (Attachment 7) details the specific analyses that should be undertaken and describes how the transportation mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable. The transportation plan requirement in the RDSGEIS is a good first step, but additional detail is needed on the transportation plan including required contents, methodologies and impact criteria to make this mitigation measure meaningful.

3.17 Noise and Vibration

The construction and operation phase noise impact assessments presented in RDSGEIS are improved over the 2009 DSGEIS, but still contain important flaws that understate the impacts.

For example, the drilling and fracturing impact assessment presented is for one well, ignoring the cumulative impact of multiple wells being developed at the same time. Even using the analysis for a single well, the sound levels associated with the fracturing process are so extreme that hearing damage could result from exposure for 8-hours at a distance of 500 feet from the well pad.

Transportation-related noise impacts are not quantified in the RDSGEIS. Potential noise effects on wildlife are not evaluated, even though the noise of a single well and even more so the combination of noise of multiple wells could affect wildlife (especially sensitive bird species). The cumulative

effects of noise on wildlife habitat and fragmentation effects of almost continual disturbance are not evaluated.

Vibration impacts and low-frequency noise impacts (which are associated with health impacts) are similarly not addressed in the RDSGEIS. The LBG technical memo details the specific analyses that should be undertaken and describes how the noise mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable.

Similar to the transportation plan requirement mentioned above, the noise mitigation plan requirement lacks specificity regarding the analyses required and the thresholds that trigger the need for mitigation. A best practice template for NYSDEC to consider adopting to specify the requirements for noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38).

3.18 Visual Resources

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. This assessment should incorporate best practices for analyzing visual impacts, such as identifying the relevant view groups, landscape zones and photo simulations of well development in various contexts.

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present *and* within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not state designated significant visual resources are present. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.19 Land Use

The RDSGEIS fails to provide any analysis of the reasonably foreseeable cumulative land use impacts that would result if HVHF development goes forward in New York. This should be corrected by providing information on existing land use patterns and analyzing the impact of the level of development anticipated in the economic impact study on land use change. The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.20 Community Character

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources,

historic resources, socioeconomics, traffic, and noise.[10] The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how HVHF would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each). A complete community character impact assessment is needed (including regional cumulative impacts) to ensure appropriate mitigation measures are included in the HVHF regulatory framework.

3.21 Cultural Resources

In addition to the ecological effects of the massive ground disturbance and industrial development that will occur with HVHF in New York, the integrity of historic architectural resources, archaeological sites and culturally significant areas to Native Americans is also threatened. The RDSGEIS does not address comments provided by New York Archaeological Council during scoping in 2008 on cultural resource issues and does not adequately address this important resource topic. There is no section of the RDSGEIS specifically devoted to the direct, indirect and cumulative impacts of HVHF on cultural resource or any discussion of mitigation measures (except for impacts related to visual resources). The reliance on the 1992 GEIS for protection of cultural resources is not sufficient given the significantly different type and scale of impacts that could occur with HVHF and the length of time that passed since the 1992 GEIS was prepared. The role of the New York State Office of Parks, Recreation and Historic Preservation (OPRHP) in the review of individual permit applications is not clear in the RDSGEIS. In addition, the RDSGEIS does not explained how tribal consultation regarding impacts to cultural resources will be accomplished in a manner consistent with NYSDEC's own 2009 policy *Contact, Cooperation, and Consultation with Indian Nations*. Cultural resource impacts, mitigation measures and project-level review requirements must be addressed before HVHF is approved. Refer to the LBG technical memorandum for more information supporting these comments (Attachment 7).

3.22 Ecosystems and Wildlife

The ecological effects of HVHF and related infrastructure development include direct losses of habitat, fragmentation of existing habitats and indirect "edge effects" such as the spread of invasive species and noise disturbance of wildlife. The RDSGEIS qualitatively acknowledges these impacts and summarizes the findings of studies conducted in other locations, but does not provide build-out analyses that could quantify the range of cumulative habitat loss and fragmentation effects in New York. As evidenced by The Nature Conservancy's build-out analysis of Tioga County, such an analysis is readily achievable with existing GIS tools and datasets available to NYSDEC.[11] The RDSGEIS should include quantitative build-out analysis of habitat fragmentation and edge effects using estimates of development potential consistent with those developed for the RDSGEIS economic impact assessment and include the impacts from reasonably foreseeable infrastructure such as pipelines and compressor stations. Based on the results of the build-out analysis, NYSDEC should also analyze the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

[10] New York City Mayor's Office of Environmental Coordination. 2010. City Environmental Review Technical Manual.
[11] The Nature Conservancy. 2011 . "An Assessment of the Potential Impacts of High Volume Hydraulic Fracturing on Forest Resources."

The RDSGEIS characterizes the ecological impacts of HVHF as “unavoidable” and fails to consider alternative mitigation approaches that could lessen significant adverse environmental impacts. The site-specific ecological assessments and mitigation measures required by the RDSGEIS for well pads in grasslands greater than 30 acres and forest patches greater than 150 acres is a fragmented approach. It does not address the importance of landscape connectivity between habitat patches, which is essential to the movement and long-term viability of numerous species. A preferable methodology would be to set limits on deforestation, fragmentation and increases in impervious surface cover based upon ecological planning units such as the sub watershed. The SGEIS process should consider an alternative where rather than the current spacing unit requirements (which are intended to maximize production), land disturbance would be restricted region wide based on ecological carrying capacity. An ecologically oriented planning framework could significantly lessen the adverse impacts of HVHF development on terrestrial and aquatic systems.

In addition, consideration should be given to cumulative changes to land use within each watershed that could lead to detrimental changes in the affected stream to support critical species habitat. Limiting the percent increase in impervious area to less than five percent (inclusive of existing uses) in trout supporting watersheds, including upstream tributaries, would reduce the potential for adverse impacts to sensitive aquatic organisms and the loss of a waters best use designation.

The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline right-of-ways and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is not restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not “restoration”. It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

For supporting technical information for these comments and additional comments on ecological impacts and mitigation measures, refer to the technical report from Kevin Heatley (Attachment 8) and LBG (Attachment 7).

3.23 Climate Change

The RDSGEIS ignores the real possibility that climate change impacts will undermine the safety of HVHF operations, frustrate mitigation efforts proposed by NYSDEC, and therefore exacerbate adverse impacts to the environment and human health resulting from HVHF operations. Increases in extreme weather events, such as floods, pose considerable obstacles to the safety of HVHF operations and infrastructure in and around low-lying coastal areas and floodplains. Precipitation changes coupled with enormous surface and groundwater withdrawals may result in modified groundwater flow patterns, which may cause unexpected groundwater contamination that jeopardizes drinking water supplies. Increased temperatures can volatilize dangerous chemical compounds at drill sites, exposing workers and nearby residents to airborne carcinogens at a rate greater than would be expected by modeling baseline temperatures without climate change. Remarkably, the effect of climate change on the availability of water resources is ignored in the section on the cumulative impact of water withdrawals, and no provision is made for situations where HVHF operations and public needs may conflict over water usage. Underscoring these concerns is the notable failure of NYSDEC to conduct a comprehensive Health Impact Assessment, despite the real possibility that climate change impacts confluent with HVHF operations can pose serious human

health problems. Reliable reports on the effect of climate change on New York abound, including some produced within the last year by New York governmental bodies. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which may pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

For supporting technical information regarding these comments, refer to the technical report from Dr. Kim Knowlton (Attachment 9).

3.24 Health Impact Assessment

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, and while the RDSGEIS addresses some aspects of a subset of these health issues, it fails to address other important health risks. The RDSGEIS not only omits several issues, but also it only addresses only some aspects of other issues such as air, water quality, and heightened traffic without fully considering health impacts in those areas. Lastly, it doesn't consider health issues as a group in a formal Health Impact Assessment (HIA), including interactive effects on the health of local residents and communities. A full HIA as part of the RDSGEIS is a necessary component, as there are already numerous reports of health complaints including dizziness, sinus disorders, depression, anxiety, difficulty concentrating, and many others, among people who live near natural gas drilling and fracturing operations in other states. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

For supporting technical information regarding these comments, refer to the technical report from Dr. Gina Solomon (Attachment 10).

3.25 Induced Seismicity

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments. The justification provided is that high volume hydraulic fracturing is not expected to cause induced seismicity that will result in adverse impacts. Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. The RSDGEIS assumes that operators will manage seismic risks voluntarily and makes statements regarding the frequency of use of seismic monitoring techniques that are internally contradictory. It also fails to recognize the potential significance of unmapped faults and relies too heavily on the occurrence of natural seismicity as a future predictor of the potential for induced seismicity. Finally, it underestimates the potential adverse consequences of induced seismicity, which include risks to drinking water, well integrity, private and public property, and New York City drinking water supply infrastructure. The RSDGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary. The RSDGEIS must require operators to evaluate and manage the risk of induced seismicity from hydraulic fracturing through proper site characterization and hydraulic fracture treatment design.

For supporting technical information regarding these comments, refer to the technical report from Briana Mordick (Attachment 11).

Attachment 1

Harvey Consulting, LLC.

2011 NYS RDSGEIS

Revised Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs and

Proposed Revisions to the New York Code of Rules and Regulations

Best Technology and Practice Recommendations

Report to:

Natural Resources Defense Council (NRDC)

Prepared by:

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

January 9, 2011

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1. Introduction

This report responds to the Natural Resources Defense Council's (NRDC), and its partner organizations Earthjustice, Inc., Riverkeeper, Inc., Catksill Mountainkeeper and Delaware Riverkeeper Network, request for a review of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs and proposed revisions to the New York Code of Rules and Regulations (NYCRR).

NRDC, and its partners, requested a technical review of the RDSGEIS and the proposed revisions to the NYCRR to determine if best technology and practices were included. NRDC has also commissioned additional experts; therefore, this list of recommendations is not exhaustive and is complementary to the work assigned to other experts. A complete list of expert recommendations can be found in the summary cover letter submitted by The Louis Berger Group, Inc., on behalf of NRDC, to the New York State Department of Environmental Conservation (NYSDEC) during the RDSGEIS public comment period.

This report makes recommendations for improving the SGEIS and the proposed revisions to the NYCRR. Overall, HCLLC found that NYSDEC made a number of significant improvements in both the RDSGEIS and the proposed revisions to the NYCRR. HCLLC commends NYSDEC for integrating a number of new best practices and technology alternatives into its 2011 RDSGEIS and proposed regulations.

This report highlights the RDSGEIS areas of improvement and reinforces the importance of retaining those improvements in the final SGEIS and the proposed NYCRR revisions. However, there remain significant areas for improvement. This report provides additional technical justification and scientific support for best practices and technology that warrant further NYSDEC consideration. It also recommends area of further study. Recommendations are highlighted in blue text boxes throughout the document.

A systemic problem persists in the 2011 RDSGEIS, where NYSDEC proposes to build on the existing 1992 Generic Environmental Impact Statement (GEIS) for oil and gas drilling in NYS by providing additional information on the Marcellus Shale reservoir and high-volume hydraulic fracturing without addressing the fact that the technology and practices required by the 1992 GEIS are over two decades old.

Since 1992, numerous best technology and best management practice improvements have been made in the oil and gas industry. By relying on 1992-vintage decisions and technology as the foundation for Marcellus Shale development, NYS' RDSGEIS starts with an unstable foundation. This problem is magnified in the proposed revisions to the NYCRR where NYSDEC proposes to retain, with little revision, antiquated technology and practices for all oil and gas development in NYS, while proposing that new technology and practices only apply to HVHF operations. This creates a technically and scientifically unsupported two-tiered system for oil and gas regulation in NYS.

Accordingly, the first and most logical step in the State Environmental Quality Review Act (SEQRA) analysis is to examine the 1992 GEIS foundation and identify new best technology and best practice improvements have been made since 1992 that warrant adoption. Then, and only then, can NYS build a well-supported incremental analysis that examines the impact of new techniques such as horizontal drilling and high-volume fracture treatments.

2. Scope of SGEIS – Marcellus Only

Background: In 2009, NYSDEC proposed that the SGEIS cover all horizontal drilling and HVHF in low-permeability gas reservoirs, at all depths. However, only the Marcellus Shale Gas Reservoir was studied in any detail. The DSGEIS was incomplete for all other low-permeability gas reservoirs.

In 2009, HCLLC recommended that NYSDEC either include additional information and analysis on the impacts of exploring and developing other low-permeability gas reservoirs or limit the scope of the SGEIS to the Marcellus Shale Gas Reservoir.

NYSDEC's consultant, Alpha Geoscience, disagreed with HCLLC's recommendation to limit the SGEIS scope to the Marcellus Shale, stating that the time to modify the scope had lapsed.[1] Alpha Geoscience concluded that it would be best for NYSDEC to determine at a future date, once a specific application was before them, whether the SGEIS covered High-Volume Hydraulic Fracturing (HVHF) operations in other low-permeability reservoirs.

HCLLC disagrees with Alpha Geoscience's recommendation, because it lacks technical and scientific basis and misconstrues HCLLC's recommendation. HCLLC did not recommend that other low-permeability gas reservoirs be excluded from the analysis because they should not be studied at all. On the contrary, HCCLC recommended that if low-permeability gas reservoirs were included in the SGEIS, they should be thoroughly studied. The 2009 DSGEIS should have included a complete assessment of the Marcellus and all other low-permeability gas reservoirs in NYS; however, it did not. Unfortunately, the 2011 RDSGEIS suffers from the same lack of data on other low-permeability gas reservoirs.

Consequently, there is a technical and scientific choice that needs to be made in declaring whether the SGEIS content satisfies its title. Either the SGEIS had to be revised to cover all low-permeability gas formations in NYS, or the SGEIS had to conclude that NYSDEC has insufficient data and/or resources to examine anything more than the Marcellus Shale at this time, and limit the scope of the SGEIS.

HCLLC's 2009 recommendation was made to ensure the SGEIS document title matches its content. The title of the SGEIS purports to provide an environmental impact analysis on all low-permeability gas reservoirs, yet, as explained in HCLLC's 2009 comments, the SGEIS did not provide sufficient analysis of the Utica Shale, and provided no analysis of the other Lower Paleozoic, Devonian (other than Marcellus), and Middle to Upper Paleozoic low-permeability gas reservoirs.[2,3] If NYSDEC has additional information to support a complete SGEIS for the Marcellus and all other low-permeability gas reservoirs, it should certainly include that complete assessment.

Unfortunately, the 2011 RDSGEIS suffers from the same narrow focus on the Marcellus shale. There was little additional work completed to advance NYSDEC's understanding of exploration and development impacts from the Utica Shale and other low-permeability gas reservoirs.

[1] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 3.

[2] Ryder, R.T., 2008, Assessment of Appalachian Basin Oil and Gas Resources: Utica-Lower Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2008–1287.

[3] Milici, R.C., and Swezey, C.S., 2006, Assessment of Appalachian Basin Oil and Gas Resources: Devonian Shale-Middle and Upper Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2006-1237.

2011 RDSGEIS: The 2011 RDSGEIS provides some additional information on the Utica Shale Gas Reservoir, mostly in the form of geologic assessment. However, the RDSGEIS does not examine the peak or cumulative impacts of Utica Shale development.

No additional information is provided in the 2011 RDSGEIS on other low-permeability gas reservoirs in the region. The 2011 RDSGEIS states that industry's main focus in the near term is the Marcellus and Utica Shales; however, NYSDEC wants to cover all other low-permeability formations in the SGEIS because it may receive applications in the future for those formations:

> *The Department of Environmental Conservation (Department) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus and Utica Shales for natural gas production… Other shale and low-permeability formations in New York may also be targeted for future application of horizontal drilling and high-volume hydraulic fracturing [emphasis added].*[4]

Chapter 4 provides a geologic description of the Marcellus and Utica shale gas reservoirs; however, no other low-permeability gas reservoirs are studied. Yet, it is well known that most unconventional reservoirs vary in mineralogy, permeability, rock mechanics, and natural fracture parameters (length, orthogonal spacing, connectivity, anisotropy) and that there will be differences between formations that could lead to different drilling, stimulation, and development techniques.

Chapters 5 and 6 provide an analysis of drilling, fracturing, and development approaches in the Marcellus Shale Gas Reservoir. Chapters 5 and 6 are essentially silent on how the Utica Shale Gas Reservoir would be developed. No other low-permeability gas reservoirs are examined.

A search of the 1537 page electronic version of the RDSGEIS for the term "low-permeability gas reservoirs" shows that the term is only used a few times in the entire document. This term is used twice in the Executive Summary, where NYSDEC concludes that it has effectively studied "low-permeability gas reservoir" air quality impacts; yet, as further explained in Chapter 17 of this report there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence of the term "low-permeability gas reservoirs" is not found until page 618 in the Air Quality Section, where again, NYSDEC states that it has included the impacts of "low-permeability gas reservoirs" in the air quality analysis; yet, there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence, after the Air Quality Section, is found at page 1008, where NYSDEC defends exclusion of pipeline and compressor stations. A few minor references to this term are found at page 1071 in Chapter 9 (Alternative Actions). More simply put, the RDSGEIS contents do not match the title, and that there is insufficient information contained in the RDGSEIS to support development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS. NYS has not developed a technical or scientific case to justify that the impacts described for the Marcellus Shale are representative of the peak or cumulative impact that would result from development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS.

The 2011 RDSGEIS does not include a complete list of the formation names that it considers fit under the umbrella term of "low-permeability" formations. The only place that the term "low-permeability" formation is defined is in the Glossary at the end of the document:

> *Gas bearing rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 0.10 millidarcies.*[5]

[4] 2011 NYSDEC, RDSGEIS, Page 1-1.

[5] 2011 NYSDEC, RDSGEIS, Glossary.

Using this definition, a low-permeability formation could include a shale, sandstone, limestone or other formation that is gas bearing with a permeability of less than 0.10 milidarcies. The RDSGEIS does not address the scope of the formations that could be encompassed by this definition.

Figure 4.2 of the RDSGEIS[6] includes a stratigraphic section showing existing known oil and gas intervals above the Marcellus and Utica Shales, including numerous shale and other low-permeability formations that are known to exist, that were not examined in the SGEIS.

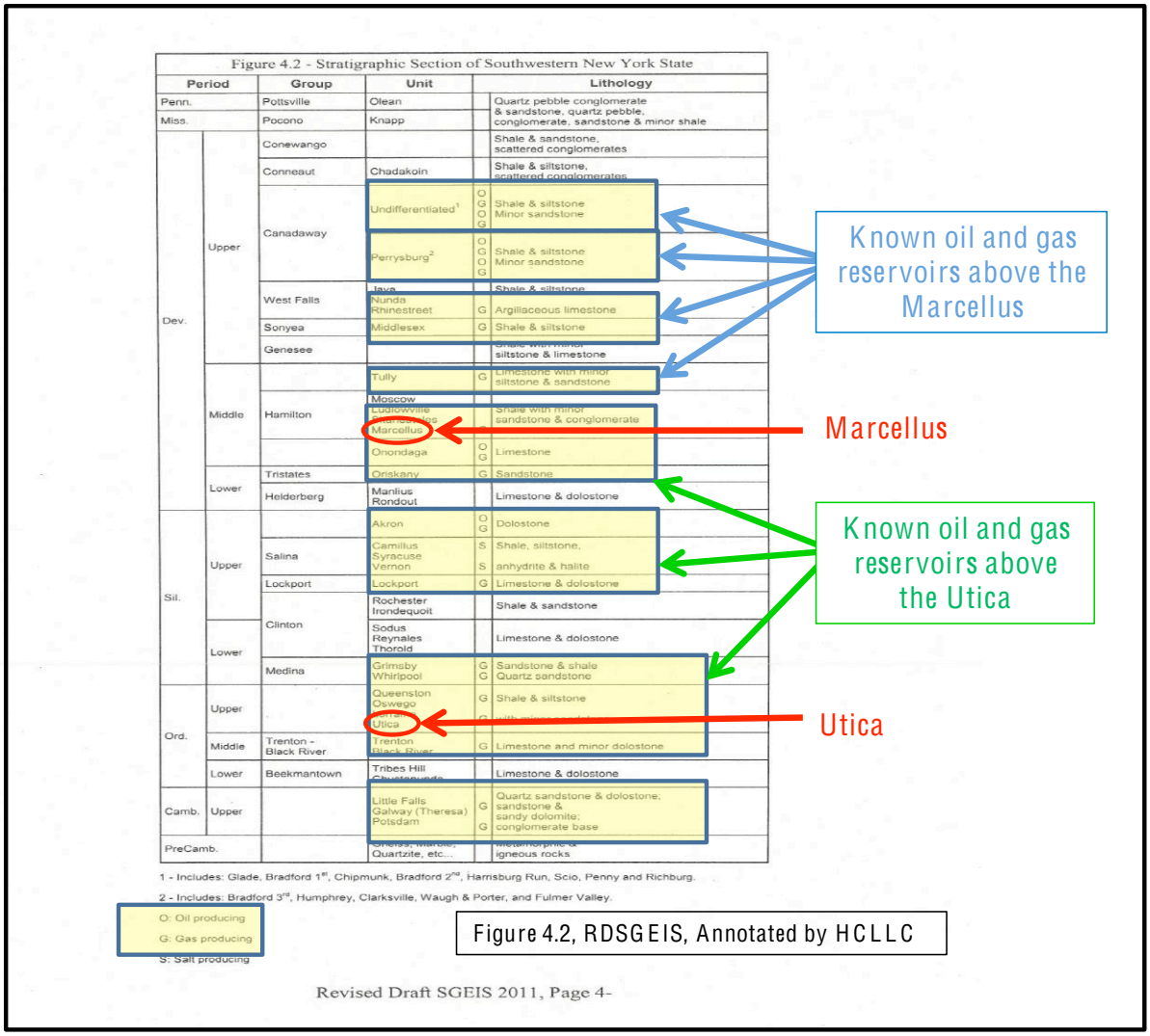


Figure 4.2 - Stratigraphic Section of Southwestern New York State

Period		Group	Unit		Lithology
Penn.		Pottsville	Olean		Quartz pebble conglomerate & sandstone, quartz pebble, conglomerate, sandstone & minor shale
Miss.		Pocono	Knapp		
Dev.	Upper	Conewango			Shale & sandstone, scattered conglomerates
		Conneaut	Chadakoin		Shale & siltstone, scattered conglomerates
		Canadaway	Undifferentiated[1]	O G O G	Shale & siltstone Minor sandstone
			Perrysburg[2]	O G O G	Shale & siltstone Minor sandstone
		West Falls	Java Nunda Rhinestreet	G	Shale & siltstone Argillaceous limestone
		Sonyea	Middlesex	G	Shale & siltstone
		Genesee			siltstone & limestone
	Middle		Tully	G	Limestone with minor siltstone & sandstone
		Hamilton	Moscow Ludlowville Skaneateles		Shale with minor sandstone & conglomerate
			Marcellus		
			Onondaga	O G	Limestone
	Lower	Tristates	Oriskany	G	Sandstone
		Helderberg	Manlius Rondout		Limestone & dolostone
Sil.	Upper		Akron	O G	Dolostone
		Salina	Camillus Syracuse Vernon	S S	Shale, siltstone, anhydrite & halite
		Lockport	Lockport	G	Limestone & dolostone
	Lower	Clinton	Rochester Irondequoit		Shale & sandstone
			Sodus Reynales Thorold		Limestone & dolostone
		Medina	Grimsby Whirlpool	G G	Sandstone & shale Quartz sandstone
Ord.	Upper		Queenston Oswego Lorraine Utica	G	Shale & siltstone
	Middle	Trenton - Black River	Trenton Black River	G	Limestone and minor dolostone
	Lower	Beekmantown	Tribes Hill Chuctanunda		Limestone & dolostone
Camb.	Upper		Little Falls Galway (Theresa) Potsdam	G G	Quartz sandstone & dolostone; sandstone & sandy dolomite; conglomerate base
PreCamb.			Sharpe, Marble, Quartzite, etc...		Metamorphic & igneous rocks

1 - Includes: Glade, Bradford 1st, Chipmunk, Bradford 2nd, Harrisburg Run, Scio, Penny and Richburg.

2 - Includes: Bradford 3rd, Humphrey, Clarksville, Waugh & Porter, and Fulmer Valley.

O: Oil producing
G: Gas producing
S: Salt producing

On the next page is a table summarizing historical oil and gas production data from 1967 to 2010 in NYS.[7] This table shows that there is numerous gas zones present both above and below the Marcellus Shale that have been producing gas. Some of these reservoirs are low-permeability reservoirs that may be further developed using horizontal drilling and hydraulic fracturing techniques. Additionally, this table shows that there has been no Utica Shale production in NYS from 1967 to 2010; therefore, little is known about its productivity or how it may be developed.

[6] 2011 NYSDEC, RDSGEIS, Page 4-7.

[7] NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011, using NYS data found at http://www.dec.ny.gov/energy/1601.html. 1967-1999 data came from summary production history files. 2000-2010 data came from oil and gas production files.

NYS Oil & Gas Data Summary 1967-2010

		Formation	Oil (bbl)	Gas (mcf)		Oil (bbl)	Gas (mcf)
Devonian	Upper	DEVONIAN SHALE	12,274	323,975			
		UPPER DEVONIAN	364,054	881,848	DEVONIAN SHALE	376,328	1,208,697
		UPPER DEVONIAN SHALE	-	2,874			
		Canadaway Undifferentiated					
		GLADE	1,392,255	449,124			
		BRADFORD	7,665,427	1,639,511			
		BRADFORD 1ST & 2ND	21	-			
		BRADFORD & CHIPMUNK	416,357	676,506			
		Bradford 1st & Chipmunk	6,609	2,497			
		CHIPMUNK, BRADFORD 1ST & 2ND	44,943	10,217			
		CHIPMUNK	7,369,293	1,012,975			
		CHIPMUNK & BRADFORD 2ND	2,454,948	16,415			
		BRADFORD SECOND	21,724	2,520			
		CHIPMUNK, BRADFORD 2ND & 3RD	237,195	162,809	CANADAWAY UNDIFFERENTIATED	23,945,472	7,271,139
		Chipmunk, Bradford 1st,2nd,3rd	9,719	8,321			
		BRADFORD 2ND & 3RD	37,780	9,353			
		CHIPMUNK & BRADFORD 3RD	33,186	34,858			
		Chipmunk & Harrisburg	2,442	1,026			
		Harrisburg	1,682	-			
		SCIO	137,258	2,520			
		PENNY	13,232	46,567			
		PENNY & FULMER VALLEY	42,660	71,003			
		RICHBURG	4,057,637	3,121,677			
		RICHBURG-WAUGH & PORTER	1,104	3,240			
		Canadaway PERRYSBURG	-	395			
		BRADFORD THIRD	228,582	112,002			
		CLARKSVILLE	39,387	36,864	PERRYSBURG	2,055,287	4,746,392
		WAUGH & PORTER	42,100	247,245			
		FULMER VALLEY	1,745,218	4,349,886			
		Nunda	-	-			
		RHINESTREET	-	3,409			
	Middle	TULLY	1,108	275,643	TULLY	1,108	275,643
		HAMILTON	-	20,416	HAMILTON	-	20,416
		MARCELLUS	-	747,399	MARCELLUS	-	747,399
		ONONDAGA	647,251	25,843,114	ONONDAGA	647,251	25,843,114
		ONONDAGA-ORISKANY	-	223,157			
	Lower	ORISKANY	10,582	31,738,725	ORISKANY	10,582	31,961,882
		HELDERBERG	-	10,230,425	HELDERBERG	-	10,230,425
		ONONDAGA-BASS ISLAND	532,310	3,118,389			
Silurian	Upper	BASS ISLAND	1,021,802	5,739,620	BASS ISLAND	1,580,509	9,416,091
		BASS ISLAND/MEDINA	26,397	558,082			
		AKRON	1,577	1,729,358	AKRON	1,577	1,729,358
		SALINA	1,278	5,778			
		CAMILLUS	-	60			
		SYRACUSE	570	2,338			
		VERNON	-	358,405			
		CLINTON	-	87,231			
		LOCKPORT	-	69,528			
		ROCHESTER SHALE	-	70,693			
		SAUQUOIT	-	210			
	Lower	SODUS SHALE	-	164,071			
		MEDINA	213,688	514,545,705			
		GRIMSBY	-	1,501,854	MEDINA	213,688	521,205,687
		WHIRLPOOL	-	893,326			
		MEDINA-QUEENSTON	-	4,264,802			
		HERKIMER	-	5,849,567			
		HERKIMER-ONEIDA	-	1,178,375			
		ONEIDA	-	1,024,647	HERKIMER-ONEIDA-OSWEGO	-	9,169,025
		ONEIDA-OSWEGO	-	1,094,384			
Ordovician	Upper	QUEENSTON	-	56,439,648	QUEENSTON	-	56,439,648
		OSWEGO	-	22,052			
		UTICA	-	-			
	Middle	TRENTON	-	485,477	TRENTON	-	485,477
		BLACK RIVER	-	318,316,063	BLACK RIVER	-	318,316,063
Cambrian	Upper	LITTLE FALLS	-	501,440	LITTLE FALLS	-	501,440
		THERESA	-	3,588,222	THERESA	-	3,588,222
		POTSDAM	-	-			

NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011.

Using the Marcellus Shale impact assessment and proposed mitigation measures as a surrogate for peak and cumulative impact assessment in the Utica and all other unnamed low-permeability formations is an inadequate approach.

For example, the Utica Shale Gas Reservoir is almost twice as deep as the Marcellus Shale Gas Reservoir. The Utica Shale dips to 9,000' deep,[8] while the Marcellus Shale is approximately 5,000' deep.[9] Utica Shale wells will take longer to drill than Marcellus Shale wells, generating more air pollution and drilling waste, HVHF waste and resulting in longer duration surface impacts (e.g. noise, light, fuel and chemical storage periods, etc.). Additionally, waste generated translates into additional transportation and surface use impacts. Utica Shale development will also require more resources and equipment. Deeper shale gas formations will have higher reservoir pressure, and will penetrate more known oil and gas zones before reaching the Utica Shale, meaning increased blowout risk. Higher reservoir pressure will require additional combustion equipment to meet higher pump pressure and energy demands. Deeper wells can have more complex well construction designs. Fully cemented casing strings will be more difficult to complete at deeper depths and higher temperature cement mixtures will be required if subsurface temperatures exceed 200 ^{0}F. Therefore, the maximum impact assessment for a Marcellus Shale well is not sufficient to examine the maximum impact of a Utica Shale well.

Additionally, there is little information in Petroleum Engineering technical literature on the Utica Shale, and how it may be effectively developed. The 2011 RDSGEIS assumes that the Utica Shale will be developed using the same exact techniques as the Marcellus Shale; however, this may not be the case. For example, a 2007 a paper prepared by Universal Well Services Inc., CESI Chemical A Flotek Industries Co., in collaboration with the State University of New York noted some significant differences in the Utica Shale, and the likelihood for a unique stimulation method:

> *The primary purpose of stimulating fractured shale reservoirs is the extension of the drainage radius via creation of a long fracture sand pack that interconnects with natural fractures thereby establishing a flow channel network to the wellbore. However, there is limited understanding of a successful method capable of stimulating Utica Shale reservoirs. Indeed most attempts to data have yielded undesirable results. This could be due to several factors, including formation composition, entry pressure, and premature pad fluid leak-off. Furthermore, stimulation of Utica shale reservoirs with acid alone has not been successful. This treatment method leads to a fracture length and drainage radius less than expected resulting in poor well productivity [emphasis added].*[10]
>
> *...several recently drilled Utica shale wells have not responded well to the normal shale fracturing practices. An understanding of Utica shale mineralogy and rock mechanics is necessary before a stimulation method and fluid are selected [emphasis added].*[11]

Additionally, the authors point out that the Utica, unlike the Marcellus, contains a high percentage of acid soluble carbonate and dolomite that may require chemical treatment (e.g. acids) to treat the carbonates and dolomite to reduce entry pressures. They suggest that an acid stimulation treatment could potentially be the main stimulation method instead of a HVHF, or alternatively be added as an additional pre-

[8] 2009 NYSDEC, DSGEIS, Page 4-5.

[9] 2009 NYSDEC, DSGEIS, Page 4-14.

[10] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 1.

[11] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 2.

treatment to a HVHF. The Utica also contains a higher percentage of clays than the Marcellus, and has the potential to generate both siliceous and organic fines that may require additional chemical treatment.

Moreover, there are low-permeability gas reservoirs that are present at depths shallower than the Marcellus Shale, which were not studied at all. Those unnamed, unanalyzed low-permeability reservoirs are in closer proximity to protected water resources, and warrant a complete technical and scientific assessment. Most importantly, HVHF modeling and fracture design requirements should be established to ensure that man-made induced fractures in these shallower reservoirs do not propagate in a manner that pollutes protected groundwater resources. Man-made induced fractures in shallower formations will tend to propagate on the horizontal plane; however, the size of that horizontal fracture must be constrained so that it does not intersect with existing improperly constructed or improperly abandoned wells or transmissive faults and fractures that can provide a direct pollution pathway to protected groundwater resources.

Best technology and best practices and cumulative impacts, in many cases, are reservoir specific. Because the RDSGEIS does not contain information on the depth, type, activity, or equipment requirements for the general category called "*other low-permeability gas reservoirs,*" it is not possible to determine if the maximum impact assessment for a Marcellus Shale well sufficiently covers the maximum impact from "*other low-permeability gas reservoirs.*" Nor is it possible to determine whether best technology and best practices developed for the Marcellus Shale would apply to the Utica Shale since there is very little information and understanding of the optimal Utica Shale stimulation method at this time.

Recommendation No. 1: The SGEIS should either include additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the SGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

3. Liquid Hydrocarbon Impacts (Oil and Condensate)

Background: NYS 2009 Annual Oil and Gas Report[12] show that NYS produced 323,536 barrels of oil in 2009, primarily from the western counties of:

Cattaraugus	201,688 barrels
Allegany	47,421 barrels
Chautauqua	40,187 barrels
Steuben	9,992 barrels

NYSDEC did not separately report the amount of condensate or natural gas liquids production.

Chapter 2 of this report includes a table summarizing oil and gas production from 1967 to 2010 in NYS, showing that oil gas been produced from above the Marcellus and Utica Shale formations, verifying the potential to encounter liquid hydrocarbons while drilling into the Marcellus and Utica formations.

2011 RDSGEIS: The 2011 RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drillsites may be needed to develop those oil resources.

Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. [13] Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.[14,15]

The 2011 RDSGEIS provided several useful maps and a stratigraphic section that aid in understanding the overlap of NYS' oil and gas production intervals. Figure 4.2 includes a Stratigraphic Section of Southwestern NYS that shows oil is produced from the Upper Devonian, at shallower depths than the Marcellus Shale, meaning that wells drilled in this region may encounter oil before penetrating the Marcellus. An annotated version of Figure 4.2 is also shown in Chapter 2 of this report. Figures 4.8 and 4.9 indicate that there is an overlap of current oil production with possible Marcellus Shale development in Cattaraugus, Allegany, Chautauqua, and Steuben counties.

Oil is also found below the Marcellus Shale and above the Utica Shale in the Upper Silurian. Therefore wells drilled into the Utica Shale may encounter oil before penetrating the Utica. Figure 4.6 indicates that there is an overlap of current oil production with possible Utica Shale development in Steuben County.

[12] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009.

[13] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[14] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

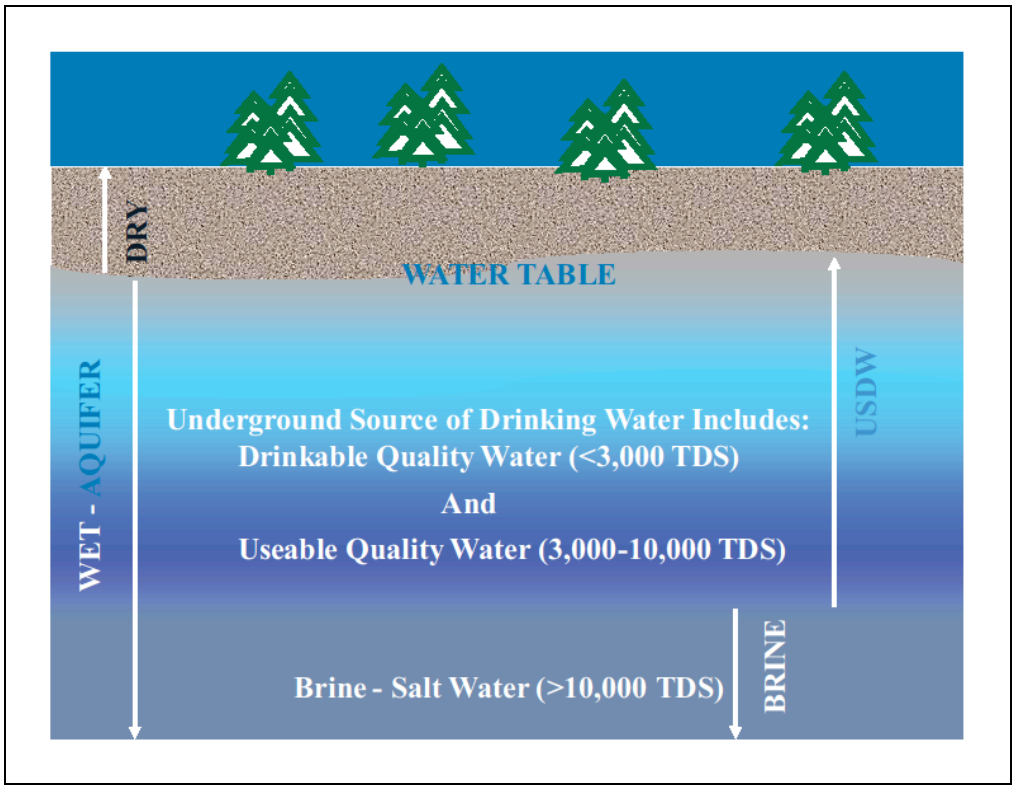
[15] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

There are low-permeability gas reservoirs that are present at depths both shallower and deeper than the Marcellus Shale, which were not studied in detail in the RDSGEIS. Absent geologic maps for these unnamed, unanalyzed low-permeability reservoirs, it is not clear where oil development and shale gas development overlap for these reservoirs may occur.

Recommendation No. 2: The SGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The SGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drillsites that may be required to develop oil resources identified by shale gas exploration and production activities.

4. Water Protection Threshold

Background: The regulations promulgated under the federal Safe Drinking Water Act (SDWA) define an Underground Source of Drinking Water (USDW) as an aquifer or part of an aquifer, which is not exempted (per 40 CFR § 146.4), and: (1) which supplies a public water system; or (2) which contains a sufficient quantity of groundwater to supply a public water system and either supplies drinking water for human consumption or contains fewer than 10,000 milligrams/liter of Total Dissolved Solids (TDS) [10,000 ppm TDS]. 40 CFR § 144.3. An EPA diagram depicting a USDW is shown below.[16]



The 2011 RDSGEIS: The 2011 RDSGEIS is based on the protection of potable water as defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS. The RDSGEIS states:

> *For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS [emphasis added].*[17]

The RDSGEIS identifies 850' as the depth where 250 ppm of sodium chloride or 1,000 ppm TDS is typically reached, however the RDSGEIS notes that in some cases potable water is found deeper than 850'.

[16] USEPA, Karen Johnson, Chief Ground Water & Enforcement Branch, 2010 PowerPoint Presentation, EPA's Underground Injection Control Program, Regulation of Disposal Wells in Pennsylvania.

[17] 2011 NYSDEC, RDSGEIS, Page 2-23.

> *Groundwater from sources below approximately 850 feet in New York typically is too saline for use as a potable water supply; however, there are isolated wells deeper than 850 feet that produce potable water and wells less than 850 feet that produce salt water. A depth of 850 feet to the base of potable water is commonly used as a practical generalization for the maximum depth of potable water; however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data [emphasis added].*[18]

By comparison, USDWs are based on a TDS cutoff of 10,000 ppm. The RDSGEIS has not explained why it proposes, and NYS regulations rely on, a 1,000 ppm TDS threshold instead of the federally required USDW threshold of 10,000 ppm TDS.

Ohio issued updated Oil and Gas Well Construction Rules on October 28, 2011, that require surface casing and intermediate casing to be set to protect the deepest underground source of drinking water (USDW); Ohio's rules are based on the 10,000 ppm federal TDS threshold.[19]

Recommendation No. 3: The SGEIS and the NYCRR should require wells to be constructed to protect Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act.

NYS' use of a 1,000 ppm TDS cut-off instead of the USDW threshold of 10,000 ppm TSD is a two-fold problem: First, the RDSGEIS states that surface casing ("water protection piping") setting depths will be 925' if no other data is available.[20] The 925' surface casing setting depth is based on an 850' base plus 75'[21], where NYSDEC has assumed that TDS will exceed 1,000 ppm at deeper than 850'. The 925' casing setting depth does not take into account the fact that drinking water, under the SDWA definition of a USDW, could exist at depths below 850'. Therefore the RDSGEIS has not provided scientific justification for the default 925' casing setting depth, nor has it explained how such a proposal comports with federal law.

Second, the entire RDSGEIS is premised on the conclusion that a HVHF well initiated at a depth of 2,000' would be safe, because NYSDEC assumes that NYS does not have any drinking water resources deeper than 850' deep. However, the RDSGEIS does not indicate that any examination of the depth of 10,000 ppm TDS water or of the availability of drinking water resources below 850' has been or will be conducted and, therefore, cannot support its 850' assumption.

Additionally, the RDSGEIS states that potable water is found deeper than 850'. Therefore, the 2,000' threshold depth for initiating a HVHF under this SGEIS requires re-evaluation. And as explained in Chapter 10 of this report, HCLLC is recommending that initial drilling and completions occur below 4,000', while site-specific data is gathered in NYS to justify safe drilling at shallower depths.

[18] 2011 NYSDEC, RDSGEIS, Page 2-23.

[19] Proposed Ohio Oil and Gas Well Construction Rules, October 28, 2011, currently under public review and comment.

[20] 2011 NYSDEC, RDSGEIS, Page 7-50.

[21] See Chapter 6 of this report, where a 100' buffer is recommended, instead of 75'.

Recommendation No. 4: The SGEIS should re-examine the 925' casing default setting and the 2000' HVHF cut-off, and justify how these proposed thresholds will protect USDW sources. Protecting to a 10,000 ppm TDS standard will likely increase both depths.

The SGEIS should include data on the location of Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act, across NYS. The SGEIS should include USDW maps for all areas that will be affected by the proposed scope of the SGEIS. This data will be an important tool for industry and the public alike to ensure USDWs are protected.

NYCRR Proposed Revisions: Well construction regulations at 6 NYCRR § 550-559 instruct operators to construct oil and gas wells in a manner that protects potable fresh water, i.e., only water containing less than 250 ppm of sodium chloride or less than 1,000 ppm of TDS. 6 NYCRR § 550.3 (ai).

The NYCRR does not protect, under its definition of "potable fresh water," water resources with less than 10,000 ppm TDS but greater than 1,000 ppm TDS, which could qualify as USDWs under the Safe Drinking Water Act. See 40 CFR §§ 144.3, 146.4.

Regulations at 6 NYCRR § 554.1 require operators to prevent pollution to "surface or ground fresh water"; however, this term is not defined by the NYCRR, so it is unclear what additional groundwater beyond "potable fresh water" would be protected or how.

Recommendation No. 5: The NYCRR should be consistent with federal law [Underground Sources of Drinking Water (USDWs)] or NYSDEC should propose more protective standards for NYS if needed to protect NYS' future water supply needs, if the federal threshold is found insufficient.

5. Conductor Casing

Background: In 2009, HCLLC recommended the NYCRR and the SGEIS be revised to include conductor casing construction standards. While a number of changes were made to improve conduct casing requirements in the RDSGEIS, the proposed revisions to the NYCRR do not include conductor casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on conductor casing and the technical basis for HCLCC's recommendations.

Conductor casing construction standards are only partially addressed in the 2011 RDSGEIS, under Appendix 10, Proposed Supplementary Permit Conditions for HVHF, and Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers.

2011 RDSGEIS: The 2011 RDSGEIS Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, includes a conductor casing requirement that limits drilling fluid types. The requirement excludes synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*

Excluding synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore is a best practice.

Appendix 9 also includes procedures for ensuring conductor pipe is cemented from top to bottom, and firmly affixed in a central location in the wellbore, with a continuous, equally thick layer of cement around the pipe.

> *If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results.*
>
> *Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*

The 2011 RDSGEIS Appendix 10, Proposed Supplementary Permit Conditions for HVHF, includes a conductor casing condition that states:

> *When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing), unless otherwise approved by the Department.*

NYCRR Proposed Revisions: In summary, NYSDEC has included important conductor casing construction guidelines in the 2011 RDSGEIS for wells drilled in primary and principal aquifer areas and HVHF wells, but has not proposed to codify those changes in the NYCRR.

The conductor casing construction guidelines listed in the 2011 RDSGEIS should apply to all wells in NYS, and should not just be limited to wells drilled in primary and principal aquifer areas and HVHF wells. These are best practices for construction of all oil and gas wells.

NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide solid structural anchorage. Also, the regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

Recommendation No. 6: Conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the NYCRR and should apply to all wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

6. Surface Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional surface casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on surface casing the technical basis for HCLCC's recommendations.

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well.

The drilling engineer determines the depth of surface casing installation with these key factors in mind: surface casing should stop above any significant pressure or hydrocarbon zone, ensuring the blowout preventer can be installed prior to drilling into a pressure or hydrocarbon zone, and surface casing should provide a protective barrier to prevent hydrocarbons from contaminating aquifers when the well is drilled deeper (below the surface casing) into hydrocarbon bearing zones.

Stray gas may impact ground water and surface water from poor well construction practices. Properly constructed and operated oil and gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion.

Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania.[22] Gas well leaks from improperly constructed gas wells have resulted in contamination of the Susquehanna River and adjacent private water supply wells.[23] A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. Duke University found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[24]

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for surface casing. Overall, NYS' surface casing requirements are fairly robust when the NYCRR, guidance documents, and standard stipulations are combined. NYSDEC proposed a number of substantial improvements in the surface casing requirements, most notably improved cement quality, casing quality, and installation techniques.

This chapter reviews the proposed changes and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and adds a few additional recommendations for NYSDEC to consider in completing its surface casing regulatory program revision.

[22] *See, e.g.*, DEP Reaches Agreement with Cabot to Prevent Gas Migration, Restore Water Supplies in Dimock Township, Agreement Requires DEP Approval for Well Casing, Cementing, November 4, 2009, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418& typeid=1.

[23] *See, e.g.*, DEP Monitors Stray Gas Remediation in Bradford County Requires Chesapeake to Eliminate Gas Migration, Chesapeake Commits to Evaluate, Remediate All PA Wells to Conform with Improved Casing Regulations, September 17, 2010, available at http://www.portal.state.pa.us/portal/server.pt/ community/newsroom/14287?id=14274&typeid=1.

[24] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane contamination of drinking water accompanying gas- well drilling and hydraulic fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, Page 2.

The main recommendation in this section is to streamline surface casing regulations by amending the NYCRR to include requirements contained in the 2011 RDSGEIS and standard stipulations. As proposed, NYSDEC has included a number of surface casing requirements in the 2011 RDSGEIS at Appendices 8, 9, and 10 (Proposed Permit Conditions). NYSDEC also included some, but not all, of these requirements in the NYCRR. Unfortunately, there are a number of inconsistencies between the permit conditions and the NYCRR that create uncertainty about what will be required.

Additionally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in NYCRR Part 560 (drilling practices for HVHF wells).

In 2009, HCLLC recommended that improved casing and cementing practices be codified in the NYCRR, rather than through a combined patchwork of permit conditions and regulations. HCLLC's concern was that the proposed requirements, in a number of cases, were inconsistent with existing regulations, and could be more efficiently consolidated into a single, more concise set of regulations.

NYSDEC's consultant Alpha Geoscience disagreed. Alpha Geoscience concluded that it would be more logical to use a patchwork of regulations, add a long list of conditions to each permit, and forgo regulatory revision.

> *Harvey Consulting suggests that NYSDEC revise the NYS oil and gas regulations to specifically address new casing and cementing practices and fresh water aquifer supplementary permit conditions. The purpose of the SGEIS, however, is not to revise regulations. The purpose of the Proposed Supplementary Permit Conditions for shale gas activities is to customize the existing regulations and guideline framework to fit new and changing industry, relieving the need for frequent regulatory changes. Permit conditions must be met by the party seeking a permit for a proposed action, so whether or not the permit conditions are included in the New York State regulations is irrelevant.*[25]

HCLLC disagrees with Alpha Geoscience's recommendation. It is relevant whether new requirements are found in regulation or a permit condition. Foremost, revising the outdated NYCRR provides simplicity and clarity for industry and the public. It provides a concise set of co-located rules. Conversely, layering a complex patchwork of permit conditions on outdated NYCRR creates confusion, inconsistency, and enforcement challenges. Furthermore, permit conditions can be revised and modified by staff, without public review, and can be applied in a more discretionary manner. Regulations are not discretionary, and are not subject to modification without a formal public review process. Therefore, HCLLC recommends that requirements that apply to all wells be codified in the NYCRR, and permit conditions be reserved for site-specific, project-specific requirements. This will improve clarity and certainty for industry and the public alike, and will afford NYSDEC the opportunity to apply site-specific, project specific requirements to address unique project issues.

NYSDEC evidently agreed with HCLLC's recommendation to revise the NYCRR by proposing revisions for public review; however, the regulations have only been partially updated to include new surface casing best practices. Therefore inconsistency remains, and needs resolution.

Recommendation No. 7: The surface casing and cementing requirements should be consistent throughout the SGEIS text and with the NYCRR.

[25] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 13.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below and compared to the proposed NYCRR revisions. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: It appears that NYSDEC's intent is to require that all wells meet the minimum standards found at Appendix 8 (NYSDEC's Casing and Cementing Practices), and then layer on additional requirements for wells drilled in primary and principal aquifers (Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers). It appears that a third layer of requirements will be applied to wells that undergo HVHF stimulation treatments (Appendix 10 Proposed Supplementary Permit Conditions for HVHF).

Therefore, it is assumed that a shale gas well that is drilled in a primary and principal aquifer, and will undergo a HVHF stimulation treatment must meet all the conditions found in Appendices 8, 9, and 10; however, this would not be possible because the permit conditions are discordant. An evaluation of these layered conditions reveals inconsistencies, as explained in the text and summary table below.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires: surface casing be set at least 75' below freshwater or at least 75' into bedrock, whichever is deeper; surface casing be set before hydrocarbons are encountered; new pipe be used (or used pipe if tested); and centralizers and cement baskets be used.

> 2. *Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper, unless otherwise approved by the Department. However, the surface pipe must be set deeply enough to allow the BOP [blow-out preventer] stack to contain any formation pressures that may be encountered before the next casing is run.*
>
> 3. *Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).*
>
> 4. *All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi), unless otherwise approved. Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.*
>
> 5. *Centralizers shall be spaced at least one per every 120 feet; a minimum of two centralizers shall be run on surface casing. Cement baskets shall be installed appropriately above major lost circulation zones.*[26]

Appendix 8 requires the use of: 25% excess cement, spacer fluids between the drilling muds and cement, and lost circulation additives. Appendix 8 also requires that gas flows or lost circulation be addressed and

[26] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 1.

the hole be conditioned before cementing. NYSDEC reserves the right to require a cement evaluation log if cement does not return to the surface.

> 6. *Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.*
>
> 7. *The pump and plug method shall be used to cement surface casing, unless approved otherwise by the Department. The amount of cement will be determined on a site-specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless other amounts of excesses are approved or specified by the Department.*[27]

Appendix 8 requires: the water used in the cement be tested for pH and temperature; the cement be prepared according to manufacturer specifications; and the cement be allowed to harden to a compressive strength of at least 500 psi before being disturbed.

> 8. *The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing ticket.*
>
> 9. *The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.*
>
> 10. *After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The waiting-on-cement (WOC) time shall be recorded on the drilling log.*[28]

The 2011 RDSGEIS Appendix 9: Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, applies to wells drilled in primary and principal aquifer zones. Appendix 9 includes conditions that require: surface casing to be set at least 100' below the deepest freshwater zone and at least 100' into bedrock; the annulus be at least 1-1/4" wide to optimize cement placement and cement sheath width: the entire annulus be cemented, using at least 50% excess cement; the cement design include additives to control lost circulation; centralizers be run at least every 120'; new pipe be used (or reconditioned tested pipe); and NYSDEC be notified and present for cementing operations.

[27] 2011 NYSDEC, RDSGEIS, Appendix 8, Pages 1-2.

[28] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

> *A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater. Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'. Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*[29]

Appendix 9 requires the surface hole be drilled using compressed air or Water-Based Muds (WBM), meaning no Synthetic-Based Muds (SBM) or Oil-Based Muds (OBM) may be used.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*[30]

As found in Appendix 9, freshwater zone depths and the potential for shallow gas hazards must be estimated and documented in drilling applications; actual data must be collected during drilling to identify any freshwater zones and shallow gas hazards that require additional NYSDEC review and approval.

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.* [31]

Appendix 9 requires cement fill the surface casing annulus, and if cement placement in the annulus is not initially successful, additional cement must be pumped into the annulus until it is filled with cement.

> *In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in*

[29] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[30] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[31] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

> *combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations.* [32]

In Appendix 9, NYSDEC reserves the right to require the operator to run a cement bond log; however, it does not require one to verify the integrity of all surface casing cement jobs.

> *This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.*[33]

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional surface casing requirements. The 2011 RDSGEIS does not explain why these additional pollution prevention and quality control/quality assurance (QC/QA) requirements do not apply to all oil and gas wells in NYS.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *b) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *c) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *d) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[34]

[32] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[33] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[34] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

Appendix 10 also requires: drilling mud be circulated and conditioned prior to cementing; spacer fluid be used to separate the drilling mud from the cement, to avoid drilling mud contamination; and cement be installed using methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond… The surface casing must be run and cemented immediately after the hole has been adequately circulated and conditioned.*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…*[35]

Appendix 10 establishes a specific period of time for the cement to harden, and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
>
> *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[36]

Appendix 10 requires records be kept for a period of 5 years and be available to NYSDEC upon request.

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[37]

[35] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[36] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[37] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 reserves the right for NYSDEC to require additional casing strings to be set in the well if the surface casing fails to adequately protect water resources or poses a safety hazard.

> *38) The installation of an additional cemented casing string or strings in the well as deemed necessary by the Department for environmental and/or public safety reasons may be required at any time.*[38]

Appendix 10 requires NYSDEC's Casing and Cementing Practices be followed. NYSDEC's Casing and Cementing Practices are included in the 2011 RDSGEIS as Appendix 8. Yet, a number of the Casing and Cementing Practices found in Appendix 8 conflict with the new requirements in Appendix 10 for wells subject to HVHF.

The RDSGEIS does not provide a rationale or basis for the use of a 75' surface casing setting depth for some wells and a 100' surface casing setting depth for others. NYSDEC determined that a 100' setting depth is best practice for groundwater protection in areas of primary and principal aquifers, but does not explain why a 100' standard would not be best practice for all wells, or at least wells that undergo HVHF.

An analysis of the surface casing permit condition requirements and inconsistencies is provided in table format as Appendix A. Recommendations are listed in the table.

NYCRR Proposed Revisions: A number of the requirements listed in the RDSGEIS Appendices 8, 9, and 10 are not codified in the NYCRR, or conflict with the proposed changes to the NYCRR.

Listed below is an analysis of the proposed NYCRR revisions for surface casing and cementing. Specific recommendations for improving surface casing design, installation, and quality control/ quality assurance requirements are also included.

Surface Casing Setting Depth: 6 NYCRR § 554.1(d) requires that:

> *surface casing shall be run in all wells to extend below the deepest potable fresh water level.*

Neither the 75' nor the 100' setting depths below the deepest protected water zone (described in the RDSGEIS) are specified in regulation. Furthermore, this regulation only protects "potable fresh water." As explained in Chapter 4 of this report, NYSDEC should consider its long-term water needs.

> Recommendation No. 8: 6 NYCRR § 554.1(d) should be revised to require the surface casing setting depth to be at least 100' below protected groundwater for all wells, or NYSDEC should provide a technical justification for reducing the setting depth to 75' for some wells.

Surface Casing Definition: 6 NYCRR § 550.3(au) reads:

> *surface casing shall mean casing extending from the surface through the potable fresh water zone.*

This definition requires surface casing be set through only the protected water zone, and does not require the casing be set deeper. This definition, as written, does not include the important requirement for the casing to be set at least 100' below protected groundwater and be cemented in place.

[38] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 8.

Recommendation No. 9: 6 NYCRR § 550.3(au) should be revised to read: surface casing shall mean casing installed and cemented from the surface, through protected groundwater, to a point at least 100' below the deepest protected groundwater. Protected groundwater should be defined in a way that meets NYS' long-term water needs.

Rotary Tool Drilling Practices: 6 NYCRR § 554.4 should be revised to be consistent with the proposed RDSGEIS surface casing conditions, and remove reference errors. 6 NYCRR § 554.4(a) provides the operator with a choice of installing surface casing in accordance with 6 NYCRR § 554.1(b) (which does not provide specific instruction to the operator) or by cementing the production casing from below the deepest potable fresh water level to the surface (which does not provide specific instruction to the operator).

> *§554.4 Rotary tool drilling practices*
>
> *(a) On all wells where rotary tools are employed, and the subsurface formations and pressures to be encountered have been reasonably well established by prior drilling experience, the operator shall have the option of either running surface casing as provided in section 554.1(b) of this Part or of cementing the production casing from below the deepest potable fresh water level to the surface. In areas where the subsurface formations and pressures to be encountered are unknown or uncertain, surface casing shall be run as provided in section 554.1(b) of this Part.*

6 NYCRR § 554.1(b) does not provide any specific direction on the type or amount of surface casing to be installed; it just says:

> *Pollution of the land and/or of surface or ground freshwater resulting from exploration or drilling is prohibited.*

Nor does 6 NYCRR § 554.4(a) provide any specific direction on the type or amount of surface casing to be installed, other than to say that it must be set below *the deepest potable fresh water level*, but the minimum depth that the casing must be set below the deepest freshwater located is not specified.

Recommendation No. 10: 6 NYCRR § 554.1(d) and 6 NYCRR § 554.4(a) should be combined or at least be consistent to require the surface casing setting depth to be at least 100' below protected groundwater.

NYCRR does not provide the operator with instructions on how to determine protected groundwater depth. The RDSGEIS explains that the depth of potable freshwater in NYS is typically 850' deep, but this depth will vary across the state. Using the 850' benchmark may not sufficiently protect all groundwater covered under the Safe Drinking Water Act. NYCRR should be revised to provide instructions to the operator on how to estimate protected water depth in drilling applications and well construction designs. NYCRR should require that depth be confirmed before setting surface casing.

Recommendation No. 11: NYCRR should require the protected groundwater depth be estimated in the drilling application to aid in well construction design. NYCRR should require the protected water depth be verified with a resistivity log or other sampling method during drilling. If the protected water depth is deeper than estimated, an additional string of intermediate casing should be required. Additionally, the NYCRR needs to be clear on whether its purpose is to protect potable freshwater only, or a broader definition of protected groundwater, which would result in surface casing being set deeper.

6 NYCRR § 554.4(b) correctly requires: cement be placed by the pump and plug or displacement methods; cement be placed in the entire annulus; and a wait on cement time before further drilling. However, 6 NYCRR § 554.4(b) does not include the best practices listed in the permit conditions (Appendices 8 and 9). Additionally, many of the best practices included in Appendix 10 for HVHF wells should be included in regulations for all oil and gas wells.

Recommendation No. 12: 6 NYCRR § 554.4(b) should be revised to be consistent with the proposed Appendices 8 and 9 permit conditions. Also, the best practices listed in Appendix 10 for HVHF should apply to all oil and gas wells and be included in 6 NYCRR § 554.4(b).

Cable Tool Drilling Practices: 6 NYCRR § 554.3 includes requirements for cable tool drilling.

Recommendation No. 13: NYSDEC should verify whether cable tool drilling is still anticipated in NYS. If cable tool drilling is still allowed, 6 NYCRR § 554.3 should be revised to require these wells be constructed to the same quality standards as wells drilled with rotary drilling equipment.

Newly proposed surface casing regulations for HVHF wells at 6 NYCRR § 560.6(c)(10) require casing be run in accordance with the "department's casing and cementing requirements." Presumably this refers to the requirements set out in the RDSGEIS at Appendix 8, but this needs to be clarified. All surface casing requirements for HVHF operations should be codified in NYCRR.

A number of new requirements proposed at 6 NYCRR § 560.6(c)(10) should be applied to all wells in NYS, not just those that will undergo a HVHF treatment. 6 NYCRR § 560.6(c)(10) proposes to add these requirements only to HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*

(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and

(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.

(11) The surface casing must be run and cemented as soon as practicable after the hole has been adequately circulated and conditioned.

The zone of critical cement (e.g. cement placed at bottom of surface casing, typically bottom 300-500') should achieve a 72-hour compressive strength standard of 1,200 psi and the free water separation for the cement should be no more than 6 ml per 250 ml of cement. For example, this requirement is found in the Pennsylvania surface casing code (25 PaCode § 78.85 (b))

An analysis of the proposed Appendices 8, 9, and 10 permit condition requirements and inconsistencies, with comparisons to NYCRR, is provided in table format as Appendix A. Recommendations for improving requirements and addressing inconsistencies are listed in the table.

Recommendation No. 14: The recommendations listed in the Surface Casing Analysis Table (Appendix A to this report) should be considered for the SGEIS and the NYCRR, including:

Surface Casing Setting Depth: NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.

Shallow Gas Hazards: If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

Cement Type: The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

Casing Quality: New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.

Cement Setting Time: Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.

NYS Inspectors: Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

Cement QA/QC: Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.

Formation Integrity Test: It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

BOP Installation: The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[39]

[39] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

7. Intermediate Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional intermediate casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on intermediate casing and the technical basis for HCLCC's recommendations.

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may set hundreds or thousands of feet of intermediate casing to: isolate unstable hole sections (to prevent collapse); isolate high or low pressure zones; isolate geologic "thief" zones prone to robbing mud from the well bore (lost circulation); put gas or saltwater zones behind pipe before drilling into the production zone; or provide additional wellbore structure.

Intermediate casing is set prior to drilling through the hydrocarbon bearing zone, and may be cemented behind the entire casing string from the top of the well to the bottom of the casing shoe, depending on intermediate casing depth. Intermediate casing provides an additional protective barrier across to prevent contamination of protected groundwater zones.

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for intermediate casing. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. NYSDEC proposed a number of substantial improvements in the intermediate casing requirements. The most notable improvement to the RDSGEIS mitigation and the NYCRR is that intermediate casing will be required in wells that undergo HVHF treatments to provide an additional protective layer of casing and cementing in the well. The RDSGEIS and the NYCRR requires intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools.

However, the remaining area for improvement in the NYCRR is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing. The proposed NYCRR is silent on the intermediate casing and cementing standards for wells that will not undergo HVHF treatment. NYS should provide instruction on intermediate casing standards for all wells that require it.

There are a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new NYCRR Part 560 (drilling practices for HVHF wells).

> Recommendation No. 15: The NYCRR should be revised to establish intermediate casing and cementing standards for all wells at NYCRR Part 554 (drilling practices for all oil and gas wells).

This section reviews the proposed changes to intermediate casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS recommends that intermediate casing be required in wells that undergo HVHF treatments, to provide an additional protective layer of casing and cementing in the well. The 2011 RDSGEIS recommends that intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools. This is an excellent recommendation. The 2011 RDSGEIS states:

> *Current casing and cementing practices attached as conditions to all oil and gas well drilling permits state that intermediate casing string(s) and cementing requirements will be reviewed and approved by the Department on an individual well basis. The Department proposes to require, via permit condition and/or regulation, that for high-volume hydraulic fracturing the installation of intermediate casing in all wells covered under the SGEIS would be required. However, the Department may grant an exception to the intermediate casing requirement when technically justified [emphasis added].*[40]
>
> *The current dSGEIS proposes to require in most cases fully cemented intermediate casing, with the setting depths of both surface and intermediate casing determined by site-specific conditions*[41]
>
> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool; and*[42]
>
> *Fully cemented intermediate casing would be required unless supporting site-specific documentation to waive the requirement is presented. This directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[43]
>
> *Depending on the depth of the well and local geologic conditions, there may be one or more intermediate casing string.*[44]
>
> *Use of centralizers to ensure that the cement sheath surrounds the casing strings, including the first joint of surface and intermediate casings.*[45]

The 2011 RDSGEIS proposes a waiver process to exclude intermediate casing under some circumstances:

> *A request to waive the intermediate casing requirement would need to be made in writing with supporting documentation showing that environmental protection and public safety would not be compromised by omission of the intermediate string. An example of circumstances that may warrant consideration of the omission of the intermediate string and granting of the waiver could include: 1) deep set surface casing, 2) relatively shallow total depth of well and 3) absence of fluid and gas in the section between the surface casing and target interval. Such intermediate casing waiver request may also be supported by the inclusion of information on the subsurface and geologic conditions from offsetting wells, if available.*[46]

[40] 2011 NYSDEC, RDSGEIS, Page 7-52.

[41] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[42] 2011 NYSDEC, RDSGEIS, Page 1-12.

[43] 2011 NYSDEC, RDSGEIS, Page 1-12.

[44] 2011 NYSDEC, RDSGEIS, Page 5-92.

[45] 2011 NYSDEC, RDSGEIS, Page 7-42.

[46] 2011 NYSDEC, RDSGEIS, Page 7-52.

The proposed waiver process conflicts with the stated intent of requiring intermediate casing for HVHF wells. The RDSGEIS states that the reason intermediate casing is required for a HVHF well is because it:

> *...directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[47]

As proposed, NYSDEC would consider a wavier if the surface casing is set "deep" or if the well is "shallow"; however, these depths are not defined. The RDSGEIS does not explain how the use of deep-set surface casing or shallow surface casing provides the same protection to aquifers as installing a second string of intermediate casing and cement.

Additionally, as proposed, NYSDEC would consider a wavier if there is an "*absence of fluid and gas in the section between the surface casing and target interval.*[48]" This requirement is incongruous, because there will always be some type of fluid in the formation between the surface casing and target interval; therefore, the conditions for this waiver to occur would never be realized.

Recommendation No. 16: The SGEIS and NYCRR should be revised to remove the waiver provisions for intermediate casing on HVHF wells, or the SGEIS and NYCRR should be revised to include technical justifications, rationale and thresholds for proposed waivers.

The 2011 RDSGEIS requires that intermediate casing be cemented and evaluated for quality as follows:

> *Intermediate casing would be cemented to the surface and cementing would be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess would suffice.*[49]

> *The operator would run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing and the production casing. The quality and effectiveness of the cement job would be evaluated using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of API Guidance Document HF1 (First Edition, October 2009). Remedial cementing would be required if the cement bond is not adequate to drill ahead and isolate hydraulic fracturing operations, respectively.*[50]

The requirements for intermediate casing are listed in Appendices 8, 9, and 10 of the RDSGEIS.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires intermediate casing be set only in certain circumstances.

> *Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.*[51]

[47] 2011 NYSDEC, RDSGEIS, Page 1-12.

[48] 2011 NYSDEC, RDSGEIS, Page 7-52.

[49] 2011 NYSDEC, RDSGEIS, Page 7-53.

[50] 2011 NYSDEC, RDSGEIS, Page 7-54.

[51] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers requires intermediate casing be set:

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.*[52]

The main problem with the conditions of Appendices 8 and 9 is that there is no specific guidance for intermediate casing and cementing, if the intermediate casing string is required as part of the well construction design.

> Recommendation No. 17: The SGEIS (Appendices 8 and 9) and NYCRR should be revised to provide specific intermediate casing and cementing requirements, as explained further in Appendix B.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional intermediate casing requirements.

The 2011 RDSGEIS Appendix 10 requires intermediate casing be set, unless a waiver is granted:

> *Intermediate casing must be installed in the well. The setting depth and design of the casing must consider all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the Department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may serve to form the basis for the Department waiving the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*[53]

The 2011 RDSGEIS Appendix 10 requires intermediate casing be completely cemented and the department be notified of cementing operations:

> *This office must be notified _____ hours prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[54]

The 2011 RDSGEIS Appendix 10 requires a cement bond evaluation log:

[52] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[53] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[54] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).*[55]

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *b) casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *c) at least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *d) cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[56]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of a spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement; and*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus...*[57]

[55] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[56] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[57] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
>
> *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[58]

Appendix 10 requires records be kept as follows:

> *i) A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.* [59]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix B. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 do not include specific requirements for intermediate casing, when intermediate casing is part of the well construction design.

A new section of regulations at 6 NYCRR § 560.6(c)(13, 14 and 15) proposes to add intermediate casing requirements for HVHF wells:

> *(13) Intermediate casing must be installed in the well. The setting depth and design of the casing must be determined by taking into account all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may be considered by the department upon a request for a waiver of the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*

[58] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[59] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

(14) As specified on a permit to drill, deepen, plug back and convert, the department must be notified prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25 percent excess cement unless caliper logs are run, in which case 10 percent excess will suffice.

(15) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the intermediate casing. Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).

Additional intermediate casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells:

(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:

(i) all casings must be new and conform to industry standards specified in the permit to drill;

(ii) welded connections are prohibited;

(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;

(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;

(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;

(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;

(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and

(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued

pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to NYCRR is provided in table format in Appendix B. Recommendations for improving requirements are listed in the table.

Recommendation No. 18: The recommendations listed in the Intermediate Casing Analysis Table (Appendix B to this report) should be considered for the SGEIS and the NYCRR, including:

Waiver Provisions: It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.

Setting Depth: Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.

Amount of Cement in Annulus: It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing cannot be fully cemented, most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.

Excess Cement: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the

current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the

well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Pressure Testing: Casing and piping should be pressure tested.[60]

[60] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, Page 109.

8. Production Casing

Background: In 2009, HCLLC recommended NYCRR be revised to include additional production casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on production casing the technical basis for HCLCC's recommendations.

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone, or alternatively sets just above the hydrocarbon zone. Production casing can be run all the way from the surface of the well across the hydrocarbon zone (production casing string) or can be hung from the surface or intermediate casing at a point deeper in the well (production liner).

If production casing is set across the hydrocarbon-producing zone, it is called a "cased hole" completion. In this scenario, production casing is lowered into the hole and cemented in place. Explosives are then lowered inside the production casing (perforation guns) to perforate holes through the pipe/cement barrier to allow oil and/or gas to enter the wellbore. In some cases, a drilling engineer may elect not to set production casing. This is called an "open hole" completion.

NYSDEC recommends a full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place. This is a best practice for HVHF wells.

Production casing is used to isolate hydrocarbon zones and contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The 2011 RDSGEIS and proposed revisions to the NYCRR include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the NYCRR is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and NYCRR requires production casing be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. NYCRR also requires the cement placement and bond be verified by well logging tools. These requirements are best practice.

NYSDEC's proposed HVHF production casing design prevents pollution of protected groundwater by constraining the HVHF pressurized fluid treatment to the inside of the production casing string as it passes the protected groundwater zone. Additionally, behind the production casing string there are two additional layers of casing and cement installed as a barrier across protected waters (e.g. surface and intermediate casing).

This section reviews the proposed changes to production casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS requires that production casing be installed and fully cemented across the production zone in wells that undergo HVHF treatments. The 2011 RDSGEIS states:

> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool.*[61]
>
> *Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch (psi) to 10,000 psi, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.*[62]

The 2011 RDSGEIS Appendix 8: Appendix 8 NYSDEC's Casing and Cementing Practices includes the following production casing requirements for all wells.

> 12. *The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.*
> 13. *Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.*
> 14. *The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.*
> 15. *The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.*
> 16. *Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.*[63]

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers does not include any additional requirements for production casing.

[61] 2011 NYSDEC, RDSGEIS, Page 1-12.

[62] 2011 NYSDEC, RDSGEIS, Page 5-92.

[63] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2-3.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional production casing requirements.

The 2011 RDSGEIS Appendix 10 requires production casing run the entire length of the wellbore, which is an excellent recommendation. Appendix 10 also requires production casing be tied into intermediate casing with at least 500' of cement:

> *36) Production casing must be run to the surface. This office must be notified _____ hours prior to production casing cementing operations. If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[64]

Appendix 10 requires a cement bond evaluation log, which is another excellent recommendation:

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*[65]

However, Appendix 10 includes a waiver provision that would exempt an operator from installing production casing cement as described above. This waiver provision is based solely on whether oil and gas might migrate from one pool or stratum to another. It does not address any of the other reasons why production casing cementing is important and required by NYSDEC in HVHF wells.

> *Any request to waive any of the preceding cementing requirements must be made in writing with supporting documentation and is subject to the Department's approval.*
>
> *The Department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will be prevented. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[66]

Recommendation No. 19: The production casing cementing waiver should be removed for HVHF wells, or NYSDEC should provide more technical justification and rationale for the waiver. NYSDEC should show how environmental protection and safety objectives can be achieved to the same level with the waiver as without it.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

[64] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[65] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[66] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:

e) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;

f) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

g) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);

h) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…[67]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

h) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…[68]

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

h) After the cement is pumped, the operator must wait on cement (WOC):

1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and

2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.[69]

[67] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[68] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[69] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 requires records be kept as follows:

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[70]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix C. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 include requirements for production casing:

> *If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing. In such instance, operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.*[71]

A new section of regulations at 6 NYCRR § 560.6(c)(16) proposes to add production casing requirements for HVHF wells.

> *(16) Production casing must be run to the surface. If installation of the intermediate casing is waived by the department, then production casing must be fully cemented to surface. <u>If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 300 feet of cement measured using True Vertical Depth</u>. Any request to waive any of the cementing requirements of this paragraph must be made in writing with supporting documentation and must be approved by the department. The department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will otherwise be prevented [emphasis added].*

The proposed regulations at 6 NYCRR § 560.6(c)(16) are inconsistent with the Appendix 10 requirement to cement the production casing with a 500' overlap into the intermediate casing.

> *If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[72]

[70] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[71] 6 NYCRR V.B. §554.4(d)

[72] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

Recommendation No. 20: A production casing 500' cement overlap into the intermediate casing is more protective; 6 NYCRR § 560.6(c)(16) should be revised to match Appendix 10.

A new section of regulations at 6 NYCRR § 560.6(c)(17) requires production casing cement be verified for HVHF wells:

> *(17) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the production casing. Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*

Additional production casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*
>
> *(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and*
>
> *(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.*

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to the NYCRR is provided in table format in Appendix C. Recommendations for improving requirements are listed in the table.

Recommendation No. 21: The recommendations listed in the Production Casing Analysis Table (Appendix C to this report) should be considered for the SGEIS and the NYCRR, including:

Casing Design: For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging, and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.

Centralizers: Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[73]

[73] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

9. Permanent Wellbore Plugging & Abandonment Requirements

Background: In 2009, HCLLC recommended that NYSDEC establish specific criteria to determine when a well must be permanently plugged and abandoned (P&A'd) and recommended improvements in NYS' well plugging regulations, incorporating best technology and practices.

Several terms are used to describe the condition of oil and gas wells that are not active hydrocarbon producers.

- Temporary Abandonment. This term is used to describe a well that may be temporarily suspended as a production well. The well may be shut-in awaiting repairs, a stimulation treatment, workover (e.g. drilling into a new zone) or a decision to finally P&A the well. A reasonable amount time should be afforded to the operator to complete the well work, or to decide when to P&A the well; however, a well should not be temporarily abandoned for a long period of time, because it poses a risk to the environment, especially if the well is known to have a leak or mechanical malfunction. Leaking or malfunctioning wells should be repaired in a timely manner or the well should be permanently P&A'd.

  In 2003, ICF Consulting produced a report for the New York State Energy Research and Development Authority (NYSERDA) that concluded NYS had 5,900 shut-in or temporarily abandoned wells, 39% of the 15,000 known wells.[74] ICF concluded that more than half the 5,900 wells have been "temporarily" abandoned for more than nine years. ICF concluded that:

  > *NYS is one of the few oil and gas producing states that have no specific regulatory provisions for long-term shut-in wells (more than two years). New York's current regulations allow an initial shut in period of one-year and an extension of up to one year, renewable for additional successive periods…*[75]

  ICF concluded that while operators are required to contact NYS to justify temporary abandonment extensions beyond one year, NYS' lack of resources to oversee the program has resulted in many wells remaining idle and not properly P&A'd for years:

  > *The practical effect is that New York's idle well regulation cannot be adequately enforced due to constraints on manpower and other agency resources, and as a result, New York has a defacto long-term inactive well program. For example New York has approximately 1,379 gas wells and 1440 oil wells with either inactive or unknown status that have no reported production since 1992.*[76]

- Permanent Abandonment. A well that is no longer needed to produce hydrocarbons should be plugged (e.g. cement barriers installed, failed casing removed, mechanical plugs set), surface equipment removed (e.g. wellhead and piping), and permanently abandoned. Operators typically do not monitor well condition once a P&A'd job is complete and approved by an agency.

[74] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 1. A final version of this report could not be located on the world-wide web.

[75] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 5.

[76] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 36.

- Improperly Abandoned Well. This term describes a well that was P&A'd, but was done so in a manner where the well still poses a risk to the environment (e.g. insufficient barriers or cement used to seal the well). Because operators typically do not monitor the condition of P&A'd wells, improperly abandoned wells often go un-resolved.

  The problem of improperly abandoned wells in NYS may be a significant issue, because NYS' P&A regulations currently only require 15' cement plugs, which NYSDEC now recognizes as deficient. Therefore, most wells in the state were not P&A'd using a quality standard that would be considered best technology and best practice today.

- Orphaned Well. This term describes a well that was orphaned by the well operator (e.g. insolvent, absentee, or non-responsive well owners) and the well was not P&A'd. Because, by definition, an "orphaned well" does not have an operator to monitor its condition, permanent abandonment of these wells typically becomes a government or property owner responsibility. Given limited agency resources, the magnitude of the environmental hazard posed by any particular orphaned well often is unknown. Unless government or property owners make it a priority to fund well monitoring or plug the well, the potential environmental impacts of orphaned wells cannot be ascertained.

In 2003, ICF Consulting, further examined 4,140 of the long-term inactive wells in NYS and concluded that:

- 546 of the 4,140 wells (13%) were drilled and completed before 1924 (over 87 years old now);
- 1,568 of the 4,140 wells (38%) were drilled and completed from 1924-1964 (at least 47 years old now, and possibly up to 87 years old); and
- 2,026 of the 4,140 wells (49%) had no information on the date of complete or condition.[77]

Therefore, there are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned).

NYS' 2009 Annual Oil and Gas Report[78] shows improperly abandoned and orphaned wells continue to be a significant problem in NYS. NYSDEC reports:

> *Abandoned, unreported and inactive wells continued to be a problem. In 2009 a total of 450 operators reported 3,043 wells with zero production. This is in addition to over* ***4,100 orphaned and inactive wells in the Department's records****. Enforcement actions have reduced the number of unreported wells yet some operators refused to file their annual reports. The operators that remained out of compliance have been referred to the Office of General Counsel for additional enforcement actions.[emphasis added]*
>
> *DEC has at least partial records on 40,000 wells, but estimates that over 75,000 oil and gas wells have been drilled in the State since the 1820s. Most of the wells date from before New York established a regulatory program. Many of these old wells were never properly plugged or were plugged using older techniques that were less reliable and long-lasting than modern methods. [emphasis added]*

[77] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 32.

[78] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009, pp. 22-23.

> *Every year while conducting scheduled inspections or investigating complaints, DEC staff discover more abandoned wells. Extensive courthouse research is often required to identify a well's previous owners. Many of these cases take several years to resolve as DEC pursues legal action against the responsible parties.*
>
> *New York has an Oil and Gas Account which was created to plug problem abandoned wells. It is funded by a $100 per well permit fee; at the end of 2009 the balance was $208,806. DEC has over 500 wells on its priority plugging list. Since the funds are insufficient to plug all the priority wells, DEC continues to pursue other mechanisms to plug abandoned wells [emphasis added].*

Well construction standards, techniques and technology have improved over time, and it is reasonable to assume that most of these long-term idle wells were not constructed to today's standards, have been subject to mechanical wear and corrosion, and warrant proper abandonment to mitigate risk to protected groundwater resources.

To compound problems, many wells that have not been properly abandoned do not have financial security (e.g. bonds) in place to fund P&A work. ICF reported that, in 2003, NYS had more than 3,500 wells that needed to be P&A'd, but there was no financial security in place (e.g. wells that were grandfathered from NYS bonding requirements). Additionally, ICF reported that 675 of the existing oil and gas wells in NYS have operators that do not comply with the current bonding requirements, and numerous operators that might comply with the existing bonding requirements have plugging liability in amounts that exceed NYS' current bonding requirements, which are too low and do not keep pace with the actual costs of P&A'ing wells today.[79]

The number of temporarily abandoned wells, improperly abandoned wells, and orphaned wells in NYS is a significant issue as shale gas resources are developed, because these old wells could provide a vertical conduit for pollutants to reach protected aquifers. Shale gas wells drilled and fracture stimulated nearby a temporarily abandoned, improperly abandoned, or orphaned well pose a risk. For example, a HVHF treatment can propagate a fracture that, depending on geology, HVHF design, and well depths, could pose a risk of intersection with a nearby well (active producer, abandoned or orphaned well).

Temporarily abandoned wells, improperly abandoned wells, and orphaned wells all pose a risk to the environment. Wellbore infrastructure can corrode and erode, failing over time and creating a potential pollutant pathway for hydrocarbons to move vertically through failed casing or cement to groundwater resources. These wells can either leak gas on their own or provide a vertical pollutant pathway to groundwater resources that can be activated by new well activity nearby.

In 2009, HCLLC recommended that temporary abandonment be limited to no longer than a one-year period, with a wellbore integrity monitoring requirement to ensure that the well is not leaking during temporary abandonment, and a requirement to permanently abandon the well after it is idle for more than a year. HCLLC recommended that NYSDEC carefully examine idle wells that have not been properly P&A'd and that are in close proximity to drinking water sources and in areas under consideration for new HVHF treatments, and require those wells to be P&A'd as a high priority and before shale gas drilling operations commence in those areas.

[79] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 35-36.

A report documenting specific cases of well pollution caused by NYS' improperly abandoned wells or orphaned wells could not be located; however, neighboring Pennsylvania has completed an analysis of this problem, and it sheds light on the problems NYS may encounter.

Pollution caused by improperly abandoned wells in Pennsylvania is documented in a 2009 report prepared by Pennsylvania Department of Environmental Protection (PADEP). The PADEP report lists 27 cases where improperly abandoned wells have been the source of groundwater contamination.[80] In some of the 27 cases the wells were abandoned according to the standard practices of the time, but now leak and need to be re-abandoned using improved materials and techniques. Some of the cases cited by PADEP include very old well construction techniques, for example, surface casing made out of wood that has rotted away, and wells with no surface casing or cement installed at all. These wells have provided a conduit for gas and other pollutants to reach groundwater through damaged or worn casing, poorly installed cement, or more directly where casing or cement was not initially installed.

PADEP also identified wells that need to be P&A'd, but have not yet been addressed due to the lack of a responsible party and/or on account of PADEP resource limitations.[81]

There were three cases cited by PADEP where fracture stimulations in an operating well communicated with a nearby abandoned well, causing a gas leak in the abandoned well.[82] PADEP's study highlighted the importance of locating orphaned and improperly abandoned wells near new oil and gas developments, and study shows the importance of properly abandoning wells before new development proceeds.

A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. The study found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[83] Clearly, the higher incidence rate of methane contamination in drinking water wells in shale gas extraction areas is not a coincidence, but is an indicator of shale gas drilling and completion operations mobilizing gas from the shale gas reservoir into protected aquifers. One of the most likely pathways for leaking of gas mobilized by HVHF is a nearby existing well that either was improperly constructed or improperly plugged. Given their failed cement, corroded casing, or lack of casing or cement, such improperly abandoned wells present vertical pathways to aquifers and drinking water resources.

Mechanical failure, human error, and engineering design flaws do occur in the construction and operation of wells. Indeed, groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

[80] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[81] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009. Cases include: Independent Valley News Migration, Allegheny County – SWRO – March 2009; Versailles Migration, Versailles, Allegheny County – SWRO – 2007 through 2008; Childers Migration, Washington County – SWRO – June 2005; Groshek Migration, Keating Twp., McKean County – NWRO – 2008; and Skinner Migration, Columbus Twp., Warren County – NWRO.

[82] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[83] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane Contamination of Drinking Water Accompanying Gas Well Drilling and Hydraulic Fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, p.2.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[84] PADEP inspectors "…discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County."[85] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[86]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[87]

In May 2011, PADEP determined that improper well casing and cementing in Chesapeake Energy Corporation's shallower wells allowed migration into groundwater and caused contaminated 16 families' drinking water supplies in Bradford County.[88]

Pennsylvania has found that significant planning and research is needed to identify orphaned and improperly abandoned wells before drilling nearby wells. At a 2009 Stray Gas Workshop in Pennsylvania, Garrett Velosi, from the National Energy Technology Laboratory, pointed out that one of the main problems with stray gas leaks from abandoned wells is verifying the location of improperly abandoned wells. Records on older wells are often limited or non-existent. Mr. Velosi presented methods for locating unmarked abandoned wells. They include the use of historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).[89]

In January 2011, NYS' consultant Alpha Geoscience agreed that timely well plugging and abandonment requirements are important; however, it recommended that establishing "a specific timeline for plugging and abandonment is neither practical nor necessary."[90] Alpha Geoscience did not examine the large backlog of improperly abandoned wells in NYS or the risk of groundwater contamination from improperly abandoned wells located within the radius of influence of new gas wells and HVHF operations. Alpha Geoscience did not recommend any improved P&A procedures, despite NYCRR's outdated requirements. 6 NYCRR § 555.5 requires only 15' cement plugs, as compared to Texas, Alaska, and Pennsylvania regulations that require a series of 50'-200' cement plugs at various locations within the wellbore.

[84] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[85] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[86] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[87] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

[88] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[89] Veloski, G., National Energy Technology Laboratory, Methods for Locating Wells in Urban Areas – A Summary of Case Studies, Pennsylvania Stray Gas Workshop, November 2009.

[90] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011

HCLLC disagrees with Alpha Geoscience's recommendation to NYSDEC. Alpha Geoscience's recommendation also conflicts with prior advice from ICF to NYSERDA. HCLLC finds that it is practical and necessary to properly abandon wells on a reasonable timeline, and recommends that NYCRR be improved to include best practices and techniques for permanent wellbore abandonment.

2011 RDSGEIS: The 2011 RDSGEIS document is inconsistent on its recommendations for P&A'ing wells. In Chapter 5, NYSDEC concludes that no improvements are needed in the NYCRR regulations, but proposes changes to improve the regulations at 6 NYCRR § 555.5. In Chapter 6, NYSDEC concludes that it is not possible for HVHF treatments to intersect improperly abandoned wells; yet, in Chapter 7 NYSDEC proposed mitigation to address this very risk. These inconsistencies are further explained below, with recommendations for resolving them.

Chapter 5 of the RDSGEIS concludes that well plugging procedures and requirements in the existing NYCRR (described in the 1992 GEIS) are sufficient to address the risk of improperly abandoned wells. The 2011 RDSGEIS states:

> *As described in the 1992 GEIS, any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors. Proper plugging is critical for the continue protection of groundwater, surface water bodies and soil. Financial security to ensure funds for well plugging is required before the permit to drill is issued, and must be maintained for the life of the well [emphasis added].*[91]
>
> *When a well is plugged, downhole equipment is removed from the wellbore, uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. These downhole cement plugs supplement the cement seal that already exists at least behind the surface (i.e., fresh-water protection) casing and above the completion zone behind production casing.*
>
> *Intervals between plugs must be filled with a heavy mud or other approved fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 50 feet of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine from the wellbore. This plug also serves to prevent wellbore access from the surface, eliminating it as a safety hazard or disposal site. Removal of all surface equipment and full site restoration are required after the well is plugged.*
>
> *The plugging requirements summarized above are described in detail in Chapter 11 of the 1992 GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action. Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review [emphasis added].*[92]

[91] 2011 NYSDEC, RDSGEIS, Page 5-143.

[92] 2011 NYSDEC, RDSGEIS, Page 5-144.

While NYSDEC agrees that proper well P&A is critical to the protection of groundwater, surface water, and soil, it concludes that horizontal drilling and HVHF shale gas wells do not require any new or different P&A methods. However, this conclusion is inconsistent with NYSDEC's proposed revisions to the P&A procedures at 6 NYCRR § 555.5, this proposal suggests that the existing regulations do not represent best practices.

> Recommendation No. 22: The SGEIS should be revised to state that the existing P&A procedures at 6 NYCRR § 555.5 were determined to be outdated and not best practice and that NYSDEC has proposed revisions. The basis for NYSDEC's proposed revisions should be justified in the SGEIS, and include a review of other states' best practices for P&A.

Chapter 5 of the RDSGEIS does not address: (1) whether NYS has a backlog of wells requiring P&A in close proximity to drinking water sources; (2) whether NYS has a backlog of wells requiring P&A in close proximity to areas under consideration for HVHF treatments; (3) whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and (4) whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

> Recommendation No. 23: The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

For example, maps showing the location and depth of NYS' temporarily abandoned, improperly abandoned, or orphaned wells could not be located; however, this data is needed to ensure safe development of shale gas resources. The RDSGEIS proposes that operators identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[93]; however, ICF's 2003 report to NYSERDA points out that there are a large number of old wells in NYS where location or well condition data is not available in NYSDEC's Oil & Gas database. If NYSDEC has improved the Oil & Gas database to accurately document all existing wells this information should be included in the SGEIS and maps of the wells should be made available.

> Recommendation No. 24: The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

In Chapter 6 of the RDSGEIS, NYSDEC discounts the risks of new HVHF shale gas wells communicating with nearby abandoned wells. NYSDEC relies on its consultant's (ICF) analysis that concludes it is not possible for HVHF treatments to intersect with improperly abandoned wells.[94] Yet, in Chapter 7, NYSDEC recommends precautionary measures to be taken by operators to ensure that wells

[93] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[94] 2011 NYSDEC, RDSGEIS, Page 6-52.

near HVHF operations are properly P&A'd to prevent freshwater contamination. The RDSGEIS is internally inconsistent on this point and the two diametrically opposed conclusions need reconciliation.

> Recommendation No. 25: Chapter 6 of the SGEIS should be revised to be consistent with and support the Chapter 7 recommendation for HVHF operators to ensure all nearby wells are properly P&A'd before HVHF operations are conducted to mitigate the risk of HVHF treatments intersecting improperly abandoned wells. This requirement should also be codified in NYCRR.

In 2009 HCLLC recommended that preventative measures be taken to identify and properly abandon existing wells before proceeding with nearby shale gas drilling and HVHF operations. NYSDEC responded favorably to this recommendation by proposing that the operator identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[95] and by proposing that any improperly abandoned wells be plugged within that one-mile radius.[96] While NYS' recommendation is a step in the right direction, additional analysis is needed to justify the one-mile radius selected.

The RDSGEIS does not provide data on the maximum horizontal fracture propagation length that could occur at NYS' proposed 2000' depth cut-off. The RDSGEIS assumes the maximum horizontal well length will be 4000'. However, as highlighted in other sections of this report, current horizontal drilling technology allows for wells to be drilled substantially longer than 4000'. Fractures induced along that horizontal wellbore section can propagate several thousand feet from the well, depending on fracture treatment design parameters. Therefore, the wellbore length and the maximum fracture length combined could result in a radius of influence of more than one mile (5,280').

> Recommendation No. 26: The SGEIS should provide technical justification for selecting a one-mile wellbore intersection radius and should explain the maximum horizontal drilling length and horizontal fracture length that corresponds with the proposed one-mile radius. This will be especially important for shallower wells where fractures tend to propagate on a horizontal plane, and where there will be a large number of potential shallow well intersection possibilities.
>
> The SGEIS should examine the potential for longer wellbores and large fracture influence zones to occur now or in the future, and a wellbore intersection radius that corresponds to the largest areas of influence that are reasonably foreseeable should be included in the SGEIS as a mitigation measure and be codified in the NYCRR. Alternatively, if NYSDEC selects a one mile radius, the SGEIS should limit drilling length and horizontal fracture length in the SGEIS as a mitigation measure and in the NYCRR to ensure that the radius of influence does not extend beyond the one-mile impact area proposed.

The RDSGEIS proposes, in Table 11.1, that operators identify and plug wells within a one-mile radius, but this requirement is not translated into a permit condition or codified in NYCRR. Table 11.1 proposes:

> *Operators must identify and characterize any existing wells within the spacing unit and within one mile of proposed well and plug and abandon any well which is open to the target formation or is otherwise and immediate threat to the environment [emphasis added].*[97]

[95] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[96] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

[97] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

Appendix 6, PROPOSED Environmental Assessment Form Addendum requires the operator to complete the one-mile radius of investigation, yet, there is no requirement in Appendix 10 or in the NYCRR requiring the offset wells to be plugged by the HVHF operator if needed.

In direct contrast to the conclusions reached in Chapter 6, Chapter 7 of the RDSGEIS acknowledges the potential risk of HVHF wells intersecting improperly abandoned wells and proposes a process to address these risks:

> *To ensure that abandoned wells do not provide a conduit for contamination of fresh water aquifers, the Department proposes to require that the operator consult the* ***Department's Oil and*** *Gas database as well as property owners and tenants in the proposed spacing unit to determine whether any abandoned wells are present. If (1) the operator has property access rights, (2) the well is accessible, and (3) it is reasonable to believe based on* ***available records and history of drilling in the area that the well's*** *total depth may be as deep or deeper than the target formation for high-volume hydraulic fracturing, then the Department would require the operator to enter and evaluate the well, and properly plug it prior to high-volume hydraulic fracturing if the evaluation shows the well is open to the target formation or is otherwise an immediate threat to the environment.* *If any abandoned well is under the operator's control as owner or lessee of the pertinent mineral rights, then the operator is required to comply with the Department's existing regulations regarding shut-in or temporary abandonment if good cause exists to leave the well unplugged. This would require a demonstration that the well is in satisfactory condition to not pose a threat to the environment, including during nearby high-volume hydraulic fracturing, and a demonstrated intent to complete and/or produce the well within the time frames provided by existing regulations [emphasis added].*[98]

While Chapter 7 correctly acknowledges the need for P&A procedure improvement and review of nearby abandoned wells before HVHF treatments, NYSDEC incongruously proposes to limit P&A due diligence to: 1) wells that are within the HVHF well operator's control and 2) wells that are "accessible." This approach discounts the risks posed by improperly abandoned wells that are owned by another operator, orphaned, or difficult to access.

The inconsistency in P&A improvement recommendations persists in the Appendix 10 HVHF Permit Conditions where the recommended improvements in Chapter 7 are not included. The Chapter 7 recommendations are not included in the revised NYCRR either.

[98] 2011 NYSDEC, RDSGEIS, Page 7-58.

Recommendation No. 27: If a well was not properly P&A'd to current standards, the operator should be required to work with the well owner or take the initiative itself to ensure the well is properly P&A'd before new drilling begins and before a nearby HVHF treatment occurs. Approval of a HVHF well application should be conditioned on verification that any necessary P&A work is complete. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC should consider requiring operators to use a variety of proven methods to locate unmarked, abandoned wells, including: historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).

The proposed mitigation measure, requiring improperly abandoned or orphaned wells to be plugged prior to a HVHF treatment, should be included in Appendix 10, of the SGEIS and codified in the NYCRR.

Additionally, NYSDEC should request ICF to further examine additional technical and scientific questions that were not addressed in its analysis.

Foremost, ICF's report does not indicate that ICF evaluated the difference in reservoir pressure near a new shale gas wellbore, drilled into an un-depleted higher pressure gas reservoir, as compared to the lower reservoir pressure in the drainage radius around a well that previously served or is currently serving as a production well. The reservoir pressure in the drainage radius around a production well will be substantially lower creating a pressure sink around that well. By the laws of physics, gas and fluid will flow from higher pressure regimes to lower pressure regimes. Therefore, if a HVHF treatment intersects the drainage radius around a nearby pressure-depleted reservoir connected to an improperly abandoned well, the HVHF fluid and associated mobilized gas will continue to move towards the improperly abandoned well, not back to the new shale gas well as ICF suggests.

As explained in Chapter 10 of this report, industry data shows that HVHF treatments are propagating well beyond the shale zone into formations located above and sometimes below the shale, meaning that the HVHF treatment can potentially intersect the depleted well drainage area of a well that has produced from a zone above or below the shale.

However, ICF concludes that, once the HVHF treatment pressure ceases, all HVHF fluid will return to the shale gas well, and there is no possibility that HVHF fluid or associated mobilized gas will travel up an improperly abandoned well conduit. This conclusion is based on the assumption that the lowest pressure pathway for HVHF fluids injected into the formation is back to the shale gas well, but such assumption does not account for the possibility that a lower pressure regime at an abandoned or active well site could influence the flow of HVHF fluids and newly mobilized gas. It also discounts the possibility that other lower pressure intervals could be located above or below the shale zone that would preferentially accept HVHF fluids and gas mobilized during the treatment.

In these cases, HVHF fluids and gas would continue towards the improperly abandoned well and up the well conduit until pressure equilibrium is reached or into adjacent lower pressured reservoirs. This could result in HVHF fluids and associated gas that is mobilized during the HVHF treatment contaminating groundwater if an exposure pathway exists in the improperly abandoned well or from an adjacent lower pressure reservoir to a shallower protected water zone.

While it is true that HVHF fluids will flow back to the new shale gas well if such well presents the lowest pressure regime for fluid to flow to, this will not always be the case, as evidenced by the fact that not all the HVHF fluid returns to the well. The RDSGEIS states that:

> *Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well, based on a pumped fluid estimate of 2.4 million to 7.8 million gallons, as presented in Section 5.9.*[99]

Therefore, several million gallons of HVHF treatment fluid remain in the reservoir and will travel to the lowest pressure formation/regime present, including such lower pressure regimes present around nearby existing wells that have previously produced hydrocarbons. An out-of-zone HVHF, as described in Chapter 10 of this report could potentially connect with this lower pressure reservoir, if not properly designed and implemented.

Secondly, ICF's analysis did not examine the maximum horizontal distance a HVHF could travel, nor identify minimum safe separation distances between horizontal fractures and abandoned wells. Thus, ICF did not attempt, to compare the maximum HVHF length to the closest distance that an abandoned well may occur.

Instead, ICF's analysis assumes that the HVHF impact radius would always be less than the distance to a nearby well (which may not be true in all cases, and will depend on reservoir characteristics and job design). ICF concludes, without basis, that a fracture created by a HVHF would never intersect a nearby well, but does not establish the well spacing distance required for this to be true nor does it consider the fact that Marcellus Shale fractures (as shown in Chapter 10 of this report) do routinely propagate out of zone.

Additionally, the Chapter 6 conclusion that it is not possible for a HVHF treatment to intersect an improperly abandoned well is discordant with three cases cited in PADEP's 2009 Report that document situations in which fracture stimulations in operating wells communicated with nearby abandoned wells, causing gas leaks in the abandoned wells.[100] PADEP's cases confirm that fracture stimulations, if improperly designed and executed, can intersect improperly abandoned and orphaned wells.

Recommendation No. 28: The SGEIS and NYCRR should require HVHF well operators to identify previously drilled wells that may be located within the hydraulic radius of the new shale gas well that may be affected during a HVHF treatment. The operator should be required to estimate the maximum horizontal and vertical extent of the fracture length that will be propagated and ensure that there are no abandoned or improperly abandoned wells in that intersection radius. An additional safety factor should be applied in this analysis to account for uncertainty in fracture design and implementation, and the potential for the actual fracture length to be longer than estimated (e.g. a conservative analysis is needed).

The HVHF treatment size should be designed to ensure that it does not intersect with any abandoned or improperly abandoned wells, with an additional margin of safety.

[99] 2011 NYSDEC, RDSGEIS, Page 5-99.

[100] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

Any improperly abandoned wells nearby, and just outside, the intersection radius should be properly abandoned to current standards before new drilling begins and before the HVHF treatment occurs.

NYCRR Proposed Revisions: Despite the 2011 RDSGEIS conclusion that no new P&A requirements are needed, and NYSDEC's consultant's (Alpha Geoscience) recommendation that no improvements are necessary, NYSDEC proposed revisions to its existing well P&A requirements at 6 NYCRR § 555.5, Plugging Methods, Procedures and Reports:

(a) The plugging of a well shall be conducted in accordance with the following sequence of operations[:] . The Division at its discretion may require the tagging of all plugs and require casing and/or cement evaluation logs to be run to determine proper plugging procedures. The following are minimum requirements for plugging and the department may impose additional requirements: [emphasis added]

> *(1) The well bore, whether to remain cased or uncased, shall be filled with cement from total depth to at least [15] 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity. Alternatively, a bridge topped with at least [15] 50 feet of cement shall be placed immediately above each formation from which the production of oil or gas has ever been obtained in the vicinity.*
>
> *(2) [If] For any casing [is to be] left in the ground, a cement plug of at least [15] 100 feet in length shall be placed [at the bottom of such section of casing] 50 feet inside and 50 feet outside of the casing shoe . Uncemented casing must be pulled as deep as practical with a 50-foot plug placed in and above the stub of the casing. If the uncemented casing is unable to be pulled the casing must be ripped or perforated 50 feet below the shoe of the next outer casing and a 100-foot plug placed across that shoe. A [similar] 50 foot plug shall be placed at [the top of such section of casing unless it shall extend to]the surface. [In the latter event, the casing shall be capped in any such manner as will prevent the migration of fluids and not interfere with normal soil cultivation.]*
>
> *(3) If casing extending below the deepest potable fresh water level shall not remain in the ground, a cement plug of at least [15] 50 feet in length shall be placed in the open hole at a position approximately 50 feet below the deepest potable fresh water level.*
>
> *(4) If the conductor casing or surface casing is drawn, a cement plug of at least [15] 50 feet in length shall be placed immediately below the point where the lower end of the conductor or surface casing shall previously have rested. The hole thereabove shall be filled with cement, sand or rock sediment or other suitable material in such a manner as well prevent erosion of the well bore area and not interfere with normal soil cultivation.*
>
> *(5) The interval between all plugs mentioned in paragraphs (1) through (4) of this subdivision shall be filled with [a heavy mud-laden] gelled fluid with a minimum density equal to 8.65 pounds per gallon with a 10 minute gel-shear strength of 15.3 to 23.5 pounds per hundred square feet or other department approved fluid.*

NYSDEC's proposed revisions are a step in the right direction. Overall, NYSDEC proposes to require longer cement plugs, weighted mud, and some additional QA/QC procedures, including tagging the cement plugs and possibly running cement evaluation logs.

NYSDEC's existing P&A regulations require short cement plugs (15'), which are woefully inadequate, compared to current best practices of installing a series of 50'-200' cement plugs within a wellbore, and removing corroded casings to isolate water resources. Unfortunately, this means that most of NYS'

abandoned wells, if plugged to NYCRR's existing standards, are not likely to provide adequate groundwater protection. To address this problem, the P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards.

> Recommendation No. 29: P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards and this requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC's proposed increase to 50' cement plug length is an improvement; however, best practices used in other states such as Texas, Alaska, and Pennsylvania require longer cement plugs. NYSDEC should consider enhancing the regulations to require longer and additional cement barriers to ensure that hydrocarbons and freshwater are confined to their respective indigenous strata, and are prevented from migrating into other strata or to the surface. For example, while NYSDEC has proposed to revise the NYCRR to require a 50' cement barrier, Alaska requires double that protection at 100'.[101] Pennsylvania recently upgraded its P&A requirements from its previous 50' standard to plugs of 50'-100'.[102] Texas requires cement plugs ranging from 50'-200' at numerous locations in the well, and requires cement QA/QC procedures.[103] For example, Texas requires each cement plug to be a minimum of 200' in length and extend at least 100' below and 100' above the top of each hydrocarbon stratum and the base of the deepest protected water stratum, which is a substantial difference from NYS' current requirement for 15' plugs.

> Recommendation No. 30: The SGEIS mitigation measures and NYCRR should be revised to clearly specify that:
>
> Plugging a wellbore should be performed in a manner that ensures all hydrocarbons and freshwater are confined to their respective indigenous strata, and prevented from migrating into other strata or to the surface.
>
> All hydrocarbon-bearing strata should be permanently sealed off by installing a cement barrier at least 100 feet below the base to at least 100 feet above the top of all hydrocarbon-bearing strata (200' plug).
>
> The plugging of a well should include effective segregation of uncased and cased portions of the wellbore to prevent the vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to at least 100 feet above the casing shoe (200' plug).
>
> The operator should be required to submit records to NYSDEC to demonstrate that the well is P&A'd in compliance with regulations.

NYSDEC should consider specifying the grade of cement required to plug the well. It should also consider requiring the use of gas blocking agents.

[101] 20 AAC 25.

[102] PA Code, § 78.91.

[103] 16 TAC Part 1, § 3.14.

Revisions to the NYCRR include some improved QA/QC procedures, but these revisions are loosely written and do not specify when QA/QC procedures will be mandatory. For example, it is best practice to tag all cement plugs to verify placement depth; this should not be an optional, discretionary procedure. Also, NYSDEC should specify under what circumstances a cement evaluation tool will be required.

Recommendation No. 31: The SGEIS mitigation measures and NYCRR should be revised to require cement quality standards, including the use of gas blocking cement. The SGEIS and NYCRR should require tagging of all cement plugs and provide instructions on when additional cement evaluation tools must be run.

10. HVHF Design and Monitoring

Background: In 2009, HCLLC recommended that NYSDEC revise its regulations to specify and require best technology and best practices for collecting data, and modeling, designing, implementing, and monitoring a fracture treatment, including:

(a) Collecting additional geophysical and reservoir data to support a reservoir simulation model;

(b) Developing a high-quality Marcellus Shale 3D reservoir model(s) to safely design HVHF treatments;

(c) HVHF modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone;

(d) Careful monitoring of the fracture treatment, including shutting the treatment down if data indicates casing leaks or out-of-zone fractures;

(e) Starting with smaller fracture treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience (e.g. 4,000' deep and 150' thick);[104]

(f) Using the experience gained with fracture testing on deeper sections of the Marcellus to design and implement larger treatment volumes over time (potentially allowing increasingly shallower and thinner intervals *only* if technical data supports the safety of this technique); and

(g) Documenting, reporting, and remediating fracture treatment failures to ensure drinking water protection.

In 2009, HCLLC recommended that fracture treatments be carefully monitored and shut down if pressure data indicates casing leaks. HCLLC noted the American Petroleum Institute recommends continuous and careful monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate, [105] and that fracture treatments should be immediately shutdown if abnormal pressures indicate a casing leak. The 2011 RDSGEIS now requires the operator to carefully monitor fracture treatments and shut down the treatment if data indicates casing leaks or out-of-zone fractures. This is an important improvement to the SGEIS.

Experts agree that Marcellus Shale gas production can be maximized by: 1) drilling long horizontal wells to increase the drainage area and 2) conducting hydraulic fracture treatments to improve permeability and access to trapped gas. However, successful, safe development requires hydraulic fracture treatments be properly designed and sized to remain within the shale zone. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport. There is extensive industry literature on the importance of hydraulic fracture design, modeling, and field verification to optimize fracture stimulation. Therefore, in 2009 HCLLC recommended that the DSGEIS be improved to provide additional technical and scientific data and require specific mitigation, ensuring that operators are designing jobs that will not fracture out-of-zone.

[104] Smaller, deeper fracture treatments could be used initially in NYS, the performance examined, the predictive model improved based on that data, and then fracture treatment size and proximity to protected waters and other wellbores could be modified, as confidence increases in the predictive ability of the model to ensure a safe and favorable result.

[105] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

Pollutant transport and pollutant toxicity issues are addressed in Dr. Tom Myers' and Dr. Glenn Miller's reports to NRDC on the 2009 DSGEIS and the 2011 RDSGEIS. HCLLC's recommendations center on what type of data, analysis, tools, and methods an engineer/operator should have in place and use to ensure that a fracture treatment can be contained within the Marcellus Shale zone.

In 2009, HCLLC observed that NYSDEC and/or operators had not provided sufficient data to demonstrate that a HVHF treatment can be contained to the Marcellus Shale. HCLLC pointed out that the 2009 DSGEIS did not require the operator to demonstrate that it is equipped with sufficient expertise, training, qualifications, and engineering tools to safely design, implement, and assess the performance of HVHF treatments. HCLLC recommended that NYSDEC consider operator qualifications.

HCLLC's recommendations on the 2009 DSGEIS explained that it is best practice in newly developed formations, such as the NYS Marcellus Shale, to build hydraulic fracture models. Fracture models are used by engineers to safely design fracture treatments. During actual fracture stimulation treatments, data are collected to verify model accuracy, and the model is continually refined to improve its predictive capability.

Because fracture treatments may be executed several thousand feet below the surface of the earth, and can only be indirectly observed, it is important for engineers to have a 3D model to guide design. While 3D modeling is not an exact science, the model provides an engineer with an estimating method for predicting both horizontal and vertical fracture length.

As further explained below, data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability.

In newly developed areas it is important to conduct initial HVHF treatments in the lowest risk zones, far below protected aquifers and with large horizontal offsets from existing wells. Until the predictive capability of site-specific models improves from the input of actual field data, larger buffer zones should be used. Absent hydraulic fracture modeling in newly developed areas such the NYS Marcellus Shale, engineers would blindly be making decisions on the size, type, and execution of HVHF treatments.

NYS' consultant, Alpha Geoscience, agreed with HCLLC's 2009 recommendations and in January 2011 reported to NYSDEC that:

> *Harvey Consulting's [HCLLC] assessment of the dSGEIS' discussion of hydraulic fracture design and monitoring is thorough…*
>
> *Harvey Consulting has thoroughly documented its discussion of hydraulic fracture design and monitoring, citing professional journal articles, professional conference papers, technical guidance documents, and consultant reports.*[106]

Alpha Geoscience recommended to NYSDEC that HCLLC's 2009 recommendations be included in the SGEIS:

> *Harvey Consulting's ideas should be considered for inclusion in the dSGEIS as possible permit conditions, especially for the first wells drilled in an area.*[107]

[106] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 26-27.

[107] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 28.

While Alpha Geoscience's report acknowledges the importance of proper HVHF design and monitoring, it includes several misrepresentations about HCLLC's 2009 comments that require correction.

First, Alpha Geoscience incorrectly contends that HCLLC recommended industry and NYS develop separate hydraulic fracture models; this is not correct. HCLLC recommended that industry develop models, or that joint model funding be implemented as a more cost-effective approach. Typically, companies build their own proprietary models to seek competitive advantage, especially in newly developed areas where the models are used as part of the competitive bidding process. However, it is possible for one or more companies to pool resources to develop a joint model as a cost savings.

Second, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform fracture modeling at every location, including locations that have been thoroughly modeled and assessed. Alpha Geoscience concluded that this would be extremely costly compared to the technical value. HCLLC did not recommend HVHF modeling be conducted at locations that have been "thoroughly modeled and assessed." Logically, if this work has already been completed, there is no reason to repeat it.

HCLLC did recommend that NYSDEC require operators to complete modeling prior to each fracture treatment to ensure that the fracture is properly designed and planned to be contained to the Marcellus Shale zone. This is not a significant amount of work per well for experienced operators, with working models. HCLLC also recommended that operators collect data during fracture treatments to further refine hydraulic fracture models. HCLLC pointed out that as NYS shale development is in its infancy, hydraulic fracture model work has not yet been completed, and therefore is needed.

Once a hydraulic fracture model is built and populated with data specific to the NYS Marcellus Shale, running a well-specific HVHF treatment scenario is an efficient process, and an important quality control and quality assurance measure. It does not appear that Alpha Geoscience is familiar with the reservoir simulators used for oil and gas work, because their recommendation to construct a hydraulic fracture model for the Marcellus Shale, and then use it only on the initial wells constructed, is inconsistent with industry practice. Model quality improves over time. As additional data is collected and the model is refined, it becomes an increasingly valuable tool to the operator. High-quality models are an essential tool for designing fracture treatments in challenging circumstances and locations.

In 2009, HCLLC explained that industry agrees there is a high level of uncertainty in NYS Marcellus Shale development; industry recommends engineering and geophysical data work to reduce that uncertainty. HCLLC's recommendations in 2009 stated:

> *Marcellus Experience Very Limited: Marcellus Shale gas development has a high level of uncertainty. Shales by nature are very heterogeneous.[108] Industry has limited experience exploiting the Marcellus Shale using horizontal wells and slickwater fracs. The first Appalachian Basin Marcellus Shale gas well stimulation using high-volume slickwater fracture treatments was only recently performed in Southwestern Pennsylvania in 2004.[109] Therefore, industry has less than five years of experience developing the Marcellus Shale using the techniques proposed in the dSGEIS.*

[108] Cipolla, C.L., Lolon, E.P., and Mayerhofer, M.J., Reservoir Modeling and Production Evaluation in Shale-Gas Reservoirs, International Petroleum Technology Conference, Paper 13185, December 2009.

[109] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

Even NYSDEC's consultants acknowledge that industry literature on and experience with the Marcellus Shale is so limited that most of their analysis was based on development of other shale gas reservoirs, such as the Barnett and Fayetteville. NYSDEC's consultant, ICF, states that:

> *"Drilling operations, and especially multi-horizontal wells, are relatively new in Marcellus Shale. While drilling operations are underway in neighboring states as evidenced by over 450 wells in Pennsylvania for example, technical studies have yet to be published that quantify actual drilling operations in Marcellus Shale. For the most part, we have had to make assumptions, where technically appropriate, that drilling operations in other shale formations are representative of expected Marcellus operations [emphasis added].*[110]

Lack of Marcellus Shale experience increases the risk of fracturing out-of-zone, unless a conservative, step-wise approach is taken to better understand the Marcellus Shale before large scale development occurs in NYS.

NYS Marcellus Data Set Improvement Needed: Site-specific data, unique to the Marcellus Shale in NYS, must be collected to: better understand the reservoir heterogeneities; develop sophisticated three dimensional (3D) reservoir models to more accurately design fracture treatments; and examine actual fracture performance in the field. Reservoir simulation models are critical engineering design tools. The dSGEIS provides no indication that a model exists for the NYS Marcellus Shale.

Engineers use 3D models to predict fracture height, length, and orientation prior to actually performing the job at the well. The goal is to design a stimulation treatment that optimizes fracture networking and maximizes gas production, while confining fracture growth to within the gas shale target formation.[111]

Engineers examine various parameters (e.g., volume, pressure, treatment placement) to optimize a fracture treatment. Without a high-quality 3D reservoir simulation model to design a fracture treatment, operators cannot demonstrate to NYSDEC that the fracture is predicted to stay in zone.

Typically an operator would start by collecting core analysis, well logs, and other subsurface data in the area it is interested in developing, to populate a site-specific 3D reservoir model. To collect this data, additional exploration and appraisal wells must be drilled (see recommendation No. 2). The limited amount of special core analysis and core data on the Marcellus Shale, as well as overlying intervals, is described in Chapter 4 of the DSGEIS, showing a need for additional data.

Test in Deepest, Thickest Zones First: NYSDEC is proposing to allow high-volume fracture treatments, without requiring the standard of care a petroleum engineer would typically use to collect data, and model, design, and monitor fracture treatments. NYSDEC should require that additional data be collected to support a model, and initially it should only allow a few, small fracture treatments that are conducted with intensive monitoring to verify that they are designed and implemented to stay within the

[110] 2009 NYSDEC, DSGEIS, ICF Task 2 Report, Page 1.

[111] ALL Consulting, Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale, Presented at The Ground Water Protection Council 2008 Annual Forum, Cincinnati, Ohio, September 21-24, 2008.

> *Marcellus Shale. This data gathering and testing should be conducted in the deepest portions of the Marcellus Shale (below 4,000') and in the thickest section of the shale (over 150') to ensure there are adequate buffer zones to protect the environment during the data gathering and testing process. Operators should start with smaller fracture treatment sizes, collecting field data to better understand fracture performance, and use field data to calibrate that performance in the 3D model.*
>
> *Over time, with careful analysis and a conservative, step-wise approach, larger fracture treatments can be tested and carefully monitored. Over time it may be possible to safely use the treatments on thinner reservoirs and shallower reservoirs, but certainly not as a first step. High-volume fracture treatments should not be conducted until there is a sophisticated data set, model, and monitoring program to verify pre-fracture and post-fracture reservoir properties.*
>
> *Buffer Zones Needed: Vertical fractures that extend above and below the shale zone will decrease gas recovery rates by allowing vertical migration into the overlying strata, or by allowing water influx from aquifers above or below the shale. NYS has a financial incentive to ensure fracture treatments are conducted correctly, because NYS will want to maximize its royalty share and tax revenue.*
>
> *To avoid fracturing out-of-zone, engineers typically design fracture treatments with a buffer zone (an un-fractured zone at the top of the shale layer and at the base of the shale). Buffer zone size should increase with geologic and technical uncertainty. Buffer zone size may decrease as industry gains experience and data quality/quantity improves. The DSGEIS does not contain sufficient information to demonstrate that NYSDEC and/or operators proposing high-volume fracture treatments have developed engineering tools capable of computing a safe buffer zone.*

Third, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform a minifracture treatment at every location, including locations that have been thoroughly modeled and assessed. HCLLC did not recommend that a minifracture be conducted at every well. Instead, HCLLC recommended that minifractures be conducted in a few different areas of NYS to further refine hydraulic fracture models. HCLLC's 2009 recommendations stated:

> *Technology is available to assess actual fracture growth including: minifracs,[112] microseismic fracture mapping,[113] tilt surveys, well logging (e.g., tracer and temperature surveys[114]), etc.[115] These technologies can be used to provide more accurate assessments of the locations, geometry, and dimensions of a hydraulic fracture system.[116] This data*

[112] Minifracs are small fracture treatments conducted in the well to better understand fracture conductivity and flow geometry prior to implementing a large fracture treatment. Minifracs are typically used to optimize the fracture design and calibrate the fracture model. These tests involve periods of intermittent injection followed by intervals of shut-in and/or flowback. Pressure and rate are measured throughout a minifrac and recorded for subsequent analyses.

[113] Microseismic monitoring is a method that measures the seismic wave generated during a fracture treatment to map the fracture extent, and it can be used to make "real-time" changes in the fracture design and implementation program.

[114] After the fracture treatment is completed, an operator can run a temperature log in the well to measure the variation in reservoir temperature resulting from the treatment. The reservoir temperature is hotter than the fracture fluid and proppant. Cooler temperatures will be measured where frac fluid and proppant are placed. Temperature logs will provide insight into fracture location and growth outside the casing.

[115] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

[116] Schlumberger, Microseismic Hydraulic Fracture Monitoring, http://www.slb.com/content/services/stimulation/stimmap.asp.

> *can be obtained in the Marcellus Shale in a few different areas of NYS to further refine the hydraulic fracture model. Minifractures are particularly helpful in estimating fracture dimensions, fracture efficiency, closure pressure, and leakoff prior to implementing a high-volume, full-scale treatment. NYSDEC should require operators to conduct minifractures to better understand site-specific reservoir characteristics prior to conducting a high-volume fracture treatment [emphasis added].*

HCLLC's 2009 recommendations also noted that:

> ***While NYSDEC's consultant, ICF***[117]*, documents a number of the engineering methods that can be used to model, monitor, and improve fracture treatments, NYSDEC does not require any of these methods in its existing regulations. Absent a regulatory requirement, there is no assurance these methods will be used [emphasis added].*
>
> *Best practice for hydraulic fracture planning includes a detailed understanding of the in-situ conditions present in the reservoir (e.g., shale thickness, reservoir pressure, rock fracture characteristics, and special core analysis). In highly heterogeneous reservoirs, reservoir simulation is often coupled with stochastic methods (e.g. Monte Carlo analysis and geostatistical techniques) to improve the quality of the 3D reservoir model.*[118]
>
> *Data collected on previous fracture treatments in the Marcellus Shale and drilling data will be useful to refine the fracture modeling. Actual fracture treatments must be carefully monitored and implemented to ensure fractures stay within zone. Data collected during each fracture treatment should be used to calibrate the 3D reservoir model to improve future fracture treatment design.*
>
> *Peer-reviewed articles and technical data on Marcellus Shale vertical fracture growth characteristics are sparse. While fracture growth models exist at an industry level, and have been tuned for fracture treatments in the Barnett Shales and other gas reservoirs, considerable technical work is still needed to develop fracture growth models for NYS Marcellus Shale development.*
>
> *A literature review was completed by the author [HCLLC] in search of a Marcellus Shale 3D reservoir model for NYS; none was found in the petroleum engineering published literature. It is not clear if the lack of a Marcellus Shale reservoir model for NYS indicates that one does not exist, or whether industry is holding models proprietary. Yet in other shale gas developments (e.g., Barnett and Fayetteville) there is extensive industry literature on: available reservoir simulation model; completion and fracture design; and performance assessment to compare predicted fracture growth with that achieved in the field. Lack of industry literature is usually a strong indication that additional data gathering and technology development is needed.*
>
> *The data void for NYS' Marcellus Shale technical literature reinforces the need for NYSDEC to use a conservative, step-wise approach, rather than launching into a massive drilling and fracturing campaign without the data or tools in place to do a safe and effective job.*

[117] ICF International, Technical Assistance to NYS on DSGEIS, August 2009.

[118] Schepers, K.C., Gonzalez, R.J., Koperna, G.J., and Oudinot, A.Y., Reservoir Modeling in Support of Shale Gas Exploration, Society of Petroleum Engineers, June 2009.

NYSDEC should require additional information be collected by industry to better understand the geological and geophysical properties of the Marcellus Shale zone and the overlying strata between the Marcellus and drinking water aquifers.

NYSDEC should require 3D reservoir simulation models be developed to accurately predict hydraulic fracture treatment performance, and to ensure the jobs are well engineered and designed with adequate safety factors to avoid fracturing out-of-zone.

The DSGEIS must assure the public that fractures can be contained to the Marcellus Shale zone. The DSGEIS does not provide data sufficient to meet this standard. The DSGEIS does not document the existence of 3D reservoir simulation models for NYS' Marcellus Shale, nor does NYSDEC require engineers to design fracture treatments using 3D models.

While Marcellus Shale development in Pennsylvania precedes development in NYS, data collected from the Pennsylvania wells is not applicable to the NYS Marcellus Shale because the depth of burial, thickness, organic content, permeability, and other reservoir properties in NYS differ. Industry experts warn that site-specific data is critical:

"By their nature, shales are extremely variable and regional differences in structure, mineralogy and other characteristics should always be considered in treatment design...The wide geographic range [of the Marcellus Shale] has led to numerous different completion schemes being utilized as with the geographic variation comes geologic variability within the formation itself. A primary topic of [industry] discussion has been determining the optimal size and type of stimulation treatment for a given area" [119] [emphasis added].

Marcellus Shale thickness lessens substantially in western NYS to less than 75' for roughly one-third of the total anticipated development area.[120] HVHF treatments in thin shale zones increases the risk of fracturing out-of-zone, unless a very cautious approach is taken by tailoring the design to the geophysical properties of the shale, taking into account shale thickness, local stress conditions, compressibility, and rigidity.

NYSDEC's consultants point out that a gas operator has no incentive to fracture out of the Marcellus Shale zone, because doing so could result in a loss of gas reserves or an increase in produced water volumes. Yet, NYSDEC's consultant, ICF, also recognizes that fracture design is complicated and it is possible to inadvertently fracture out-of-zone. ICF examined the potential for fracture fluids to propagate vertically and contaminate overlying drinking water aquifers. ICF recommended a 1,000' vertical offset be used.

HCLLC agrees that the use of vertical and horizontal offsets (buffer zones) is a prudent approach. The next step is to determine the size of the offsets. Initially, in new areas, offsets should be large, and then may decrease over time, as field data is obtained and predictive capability is refined.

[119] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

[120] 2009 NYSDEC, DSGEIS, Figure 4.9.

In 2009, HCLLC pointed out that the 1,000' vertical offset proposed by ICF is not technically supported, and a horizontal buffer zone is also needed. HCLLC recommended that vertical and horizontal offsets be based on actual field data, 3D reservoir simulation modeling, and a peer-reviewed hydrological assessment. HCLLC recommended these steps be taken to ensure aquifers are protected and nearby wellbore intersections are avoided.

The 2011 RDSGEIS still does not provide technical justification for the proposed minimum 1,000' vertical offset, nor does it make a recommendation for a horizontal offset from existing wells.

Instead, the 2011 RDSGEIS provides data that shows HVHF treatments in the Marcellus Shale have propagated vertical fractures up to 1500' in length, and horizontal fractures can extend hundreds to thousands of feet, as further explained below. These data do not support the proposed buffers.

The 2011 RDSGEIS: The 2011 RDSGEIS agrees that in new areas hydraulic fracture model development and design is important, citing recommendations from the Ground Water Protection Council and its consultant ICF; yet, incongruously the RDSGEIS concludes it is unnecessary for operators to be required do this work in NYS (as a SGEIS mitigation measure or a NYCRR requirement).

> *Service companies design hydraulic fracturing procedures based on the rock properties of the prospective hydrocarbon reservoir. For any given area and formation, hydraulic fracturing design is an iterative process, i.e., it is continually improved and refined as development progresses and more data is collected. In a new area, it may begin with computer modeling to simulate various fracturing designs and their effect on the height, length and orientation of the induced fractures. After the procedure is actually performed, the data gathered can be used to optimize future treatments. Data to define the extent and orientation of fracturing may be gathered during fracturing treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging. ICF International, under contract to NYSERDA to provide research assistance for this document, observed that fracture monitoring by these methods is not regularly used because of cost, but is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models [emphasis added].*[121]

NYSDEC's consultants (Alpha Geoscience and ICF), the Ground Water Protection Council, HCLLC, and industry all agree:

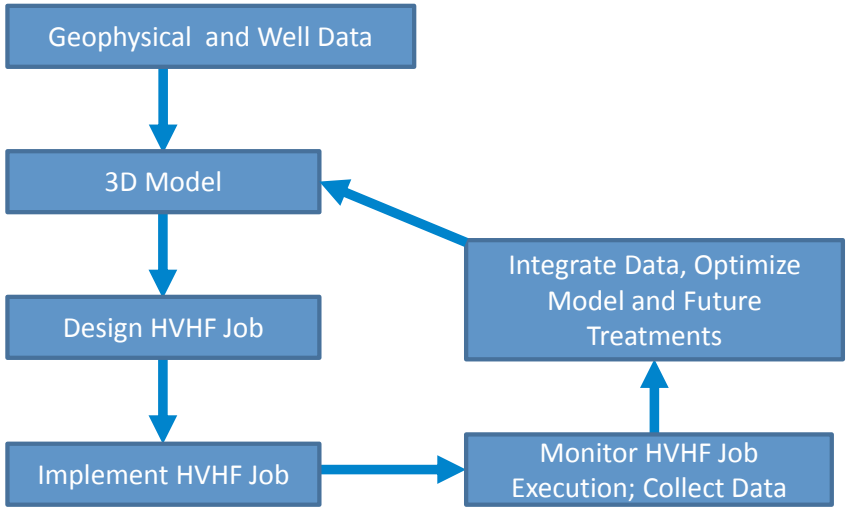
- There is a need for computer modeling on new gas shale play areas to simulate various fracturing designs and their effects on the height, length, and orientation of the induced fractures;
- After the HVHF treatment is actually performed, gathered data should be used to optimize future treatments; and
- There is technology available to further refine treatment design, including microseismic fracture mapping, tilt measurements, tracers, and proppant tagging.

However, these points of agreement are not reflected in the RDSGEIS, permit conditions, or NYCRR revisions. Remarkably, the 2011 RDSGEIS only has a few paragraphs in the entire 1,537 page document that discuss the importance of HVHF modeling and post-fracture assessment work (Chapter 5.8), and these recommendations are later disregarded in Chapter 7 proposed mitigation.

[121] 2011 NYSDEC, RDSGEIS, Page 5-88.

The use of 3D reservoir simulation to more accurately predict vertical and horizontal fracture growth is not new; reservoir simulation models have been used by petroleum engineers for decades. However, computational efficiency and model design have improved considerably, and more sophisticated simulation techniques are now available for shale gas reservoirs.

The basic engineering approach for populating a 3D reservoir simulation model is shown in the simplified flow diagram below, with geophysical data (seismic, well logs, core, samples, etc.) and existing nearby well data serving as the starting point. Once a model is built, it is used to design and optimize a safe and effective HVHF job. Data are gathered while the job is implemented, and those data are used to refine the model and improve future HVHF treatments.



There is abundant industry literature explaining the need for hydraulic fracture modeling and microseismic mapping, especially for new shale play developments, such as in NYS.

NYSDEC should recognize that the use of refined, site-specific models to optimize HVHF jobs is industry best practice. Quality operators with high standards routinely do this work. It should not be considered a burdensome practice, but rather a necessary requirement to protect groundwater and the environment.

Furthermore, it is economically attractive for an operator to use HVHF modeling. Models aid industry in making informed decisions, and prevents fracturing out-of-zone, which maximizes gas recovery rates.

Microseismic mapping has become a key tool for better understanding shale gas heterogeneities, identifying reservoir faults, and measuring actual fracture propagation orientation and length.

A 2010 industry paper[122] written by Rex Energy Corporation and MicroSeismic Inc. explains the importance of microseismic mapping for shale gas engineering:

> *By using microseismic source locations and mechanisms in conjunction with other geological and geophysical knowledge of an area, engineering and completion methods can be quickly corrected and enhanced. Induced fracture height, length, and placement influence the location, orientation and spacing of subsequent wells. Microseismic monitoring allows for identification and characterization of unknown faults which intersect the wellbore and may significantly affect reservoir production and stimulations. Formations with limited exploration with limited exploration data, such as the Marcellus shale, are ideal candidates for microseismic monitoring [emphasis added].*
>
> *In this case study, we will show how the microseismic monitoring of a hydraulic fracture treatment in the Marcellus Shale identified a pre-existing natural fault which intersected the wellbore [emphasis added].*

A 2011 industry paper[123] written by Marquette Exploration (a Marcellus Shale operator) and Schlumberger (an industry contractor), titled "Integrating All Available Data to Improve Production in the Marcellus Shale," emphasizes the importance of HVHF design and monitoring:

> *The operator featured in this paper is a small independent with Marcellus Shale areas of operation spanning across Belmont and Jefferson counties, eastern Ohio (Fig.2). This paper describes the methodology used by the operator to systematically gather the critical data during a pilot program to enhance the knowledge of their reservoir and develop optimized completion strategies and stimulation designs, thereby maximizing the true economic value of their asset.*
>
> *To build realistic property models, input from team members from different disciplines is required; in this study, team members included a geophysicist, geologist, petrophysicist, and reservoir engineer. Once the 3D structural model was completed, individual log measurements and interpreted properties from petrophysical, geomechanical, and image logs were incorporated in the model.*

Marquette Exploration's paper concludes:

- *Delineating a reservoir early on in the play and gathering as much data as possible can improve the drilling and completion design of the initial horizontal wells in the field to reduce the time and cost for an operator to get up the learning curve.*
- *Using all available data can greatly enhance the understanding in a field which, in turn, can improve the lateral design. Core data are imperative to calibrate petrophysical and geomechanical logs to further refine log models in other wells in an area.*
- *Seismic data in conjunction with strategically placed vertical logs can be used to construct a detailed static 3D geological model.*

[122] Hulsey, B.J., and Cornette, B. (MicroSeismic Inc.), and Pratt, D. (Rex Energy Corporation), Surface Microseismic Mapping Reveals Details of the Marcellus Shale, Society of Petroleum Engineers, SPE Paper 138806, 2010, Page 1.

[123] Ejofodomi, E., Baihly, J., Malpani, R., Altman, R, (Schlumberger), and Huchton, T., Welch, D., and Zieche, J., (Marquette Exploration), Integrating All Available Data to Improve Production in the Marcellus Shale, Society of Petroleum Engineers Paper, SPE 144321, 2011.

- *The thickness, depth, and continuity for shale sub-layers can vary greatly over a small area, so a pilot hole can be imperative to calibrate the geologic model for lateral landing point determination.*
- *The geologic model showed that the reservoir properties varied across the area of interest.*
- *Stochastic modeling can be used to successfully propagate interpreted log properties from a few wells across a large acreage.*
- *A novel reservoir modeling technique, Microseismic Fracture Network (MFN), was developed using microseismic data to properly describe the created complex fracture network.*

A 2010 industry paper[124] written by El Paso Exploration and Production and StrataGen Engineering stresses the importance of HVHF design:

> *...a primary conclusion is that as reservoir permeability decreases, proper well type selection and effective hydraulic fracture stimulation design become much more crucial [emphasis added].*
>
> *Additional modeling with specifics must be performed to evaluate well type, fracture design, and spacing requirement for a specific well or formation [emphasis added].*

A 2011 industry paper[125] written by Schlumberger also stresses the importance of HVHF design and monitoring:

> *The completion strategy and hydraulic fracture stimulation are the keys to economic success in unconventional reservoirs. Therefore, reservoir engineering workflows in unconventional reservoirs need to focus on completion and stimulation optimization as much as they do well placement and spacing. This well-level focus requires the integration of hydraulic fracture modeling software and the ability to utilize measurements specific to unconventional reservoirs [emphasis added].*
>
> *It is very important to properly model hydraulic fracture propagation and hydrocarbon production mechanisms in unconventional reservoirs, a significant departure from conventional reservoir simulation workflows. Seismic-to-simulation workflows in unconventional reservoirs require hydraulic fracture models that properly simulate complex fracture propagation which is common in many unconventional reservoirs, algorithms to automatically develop discrete reservoir simulation grids to rigorously model the hydrocarbon production from complex hydraulic fractures, and the ability to efficiently integrate microseismic measurements with geological and geophysical data. The introduction of complex hydraulic fracture propagation models now allows these workflows to be implemented [emphasis added].*

A 2010 industry paper[126] written by StrataGen Engineering and CMG (industry consultants) again highlights the importance of HVHF design and monitoring:

[124] Shelley, R.F., Lolon, E., and Dzubin, B. (StrataGen Engineering), and Vennes, M. (El Paso Exploration and Production), Quantifying the Effects of Well Type and Hydraulic Fracture Selection on Recovery for Various Reservoir Permeability Using a Numerical Reservoir Simulator, Society of Petroleum Engineers Paper, SPE 133985, 2010, Pages 1 and 12.

[125] Cipolla, C.L., Fitzpatrick, T., Williams, M.J., and Ganguly, U.K., (Schlumberger), Seismic-to-Simulation for Unconventional Reservoir Development, Society of Petroleum Engineers Paper, SPE 146876, 2011, Page 1.

> *The widespread application of microseismic mapping has significantly improved our understanding of hydraulic fracture growth in unconventional gas reservoirs (primarily shale) and led to better stimulation designs. However, the overall effectiveness of stimulation treatments is difficult to determine from microseismic mapping, as the location of proppant and distribution of conductivity in the fracture network cannot be measured (and are critical parameters that control well performance). Therefore it is important to develop reservoir modeling approaches that properly characterize fluid flow in and the properties of a complex fracture network, tight matrix, and primary hydraulic fracture (if present) to evaluate well performance and understand critical parameters that affect gas recovery [emphasis added].*
>
> *Given the complex nature of hydraulic fracture growth and the very low permeability of the matrix rock in many shale-gas reservoirs combined with the predominance of horizontal completions, reservoir simulation is commonly the preferred method to predict and evaluate well performance [emphasis added].*
>
> *The most rigorous method to model shale-gas reservoirs is to discretely grid the entire reservoir, including the network fractures, hydraulic fracture, matrix blocks, and un-stimulated areas – but this increases computational time. However, with the continual advances in computing power, much more complex numerical models can be efficiently utilized.*

In 2010, Atlas Energy Resources published a Society of Petroleum Engineering Paper that explained the importance of reservoir characterization, modeling, the use of minifracs, and the use of microseismic data. Atlas Energy Resources explained that the use of advanced technology is good business:

> *This paper describes a procedure to enhance production in the Marcellus shale while optimizing economics through integration of minifrac, fracture treatment, microseismic, and production data technologies.*
>
> *Application of this integrated technology approach will help prodvide the operator with a systematic approach for designing, analyzing, and optimizing multi-stage/multi-cluster transverse hydraulic fractures in horizontal wellbores.*[127]

An engineering analysis and modeling prior to a HVHF treatment provides industry, regulators, and the public with confidence that the treatment has been thoroughly evaluated and designed to protect the environment. It is not sufficient for industry and NYSDEC to say this work is being done, while being unwilling to require it. If this work is being done, then creating a formal requirement in the SGEIS and NYCRR does not impose an incremental burden on the operator. Resistance to a formal requirement should signal to NYSDEC that industry best practice is not always followed.

While industry literature explains the need for hydraulic fracture modeling, this does not guarantee it will actually be implemented by all shale gas operators in NYS. Shale gas drilling has attracted numerous small, less experienced operators. Computational modeling requires personnel with expertise in building models, running them, and refining datasets. If the operator does not have sufficient in-house engineering and geophysical expertise, it should be required to hire experts to provide the necessary expertise.

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[126] Cipolla, C.L., Lolon, E.P. (StrataGen Engineering), Erdle, J.C., and Rubin, B. (CMG), Reservoir Modeling in Shale-Gas Reservoirs, Society of Petroleum Engineers Paper, SPE 125530, 2009, Pages 1,3, and 4.

[127] Henry Jacot, R. (Atlas Energy Resources), Bazan, L.W. (Bazan Consulting, Inc.), Meyer, B.R. (Meyer & Associates Inc.), Technology Integration – A Methodology to Enhance Production and Maximize Economics in Horizontal Marcellus Shale Wells, Society of Petroleum Engineers Paper, SPE 135262, 2010, Page 1.

Recommendation No. 32: Best practices for HVHF design and monitoring should be included in the SGEIS as a mitigation measure, and codified in NYCRR as a minimum standard.

Additionally, Alpha Geoscience, ICF, Ground Water Protection Council, HCLLC, and industry all agree that additional technical work is needed to develop new shale gas play areas; yet the 2011 RDSGEIS does not require the operator to develop or maintain a hydraulic fracture model. Instead, the 2011 RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned.[128]

Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. This approach would not be in NYS' best interest.

Instead, NYS needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective, it is also good business because it optimizes gas production and reduces hydraulic fracture treatment costs.

The 2011 RDSGEIS does not require a HVHF design plan.[129] The RDSGEIS does not require the operator to:

(a) Estimate the vertical and horizontal fracture length;

(b) Verify that the proposed HVHF design will not intersect protected groundwater or nearby wells;

(c) Use a site-specific hydraulic fracture model, based on NYS specific shale characteristics and the operational design parameters of the planned HVHF job (volume, pressure, rate, etc.).

Recommendation No. 33: The SGEIS and NYCRR should require the operator to:

(a) Estimate the maximum vertical and horizontal fracture propagation length for each well, and submit technical information (e.g. model output) with its application to support its computations.

(b) Describe in its post-well completion report whether the predicted vertical and horizontal fracture propagation lengths were accurate, or note discrepancies.

(c) Certify that the actual HVHF job was implemented safely, and fracture propagations did not intersect protected aquifers or nearby wells.

Additionally, NYS should reserve the right, and provide funding, to periodically review industry's models and computations to assess quality and verify this work is being completed.

[128] 2011 NYSDEC, RDSGEIS, Page 5-88.

[129] The operator is only required to verify that the vertical offset of 1000' is achieved and the shale is at least 2000' deep.

The 2011 RDSGEIS assumes that any HVHF job, no matter the volume, no matter the pressure, and no matter the shale thickness, will be safe, as long as it is conducted at a depth below 2,000'. The 2011 RDSGEIS recommends that site-specific SEQRA reviews be limited to wells shallower than 2000' and within 1000' of a protected aquifer.[130] The RDSGEIS lacks technical and scientific data to support the hypothesis that all HVHF treatments, regardless of design, at 2000' or deeper will be safe. Additionally, the RDSGEIS does not address safe horizontal fracture length.

NYSDEC does not provide data on HVHF treatments conducted between 2000' and 5000' deep; yet, NYS proposed to allow shale gas drilling at these depths. Instead, the RDSGEIS relies on limited data collected from Marcellus Shale fractures conducted in other states at depths below 5000'. However, even industry points out that data collected in one part of the Marcellus Shale cannot be applied to the entire shale.

For example, Guardian Exploration and Universal Well Services reports that optimal Marcellus Shale HVHF treatments are still being developed, and that a "one-size-fits-all approach should not be expected. They anticipate that industry will examine the use of higher rates and increased fluid volume and proppant mass in the future resulting in varied fracture lengths from current HVHF jobs:

> *Much work remains to be done in determining the optimal stimulation treatment for the Marcellus shale. Certainly given the extremely large geographic area encompassed by the Marcellus play, it should not be expected that one size will fit all. While the treatment discussed here has been considered successful, future projects will examine the effects of increased rate, increased volumes in terms of both overall fluid volume and proppant mass, the effects of varying the proppant mesh ratios and concentrations, and optimization of flowback/cleanup rates. The utilization of evaluation tools such as microseismic monitoring of fracture growth and horizontal drilling and completions to enhance reservoir development should also prove to be beneficial [emphasis added].*[131]

As HVHF treatment methods continue to evolve, NYSDEC must either set a limit in the SGEIS and NYCRR for the upper bounds of a safe HVHF job, or it must have a process in place for industry to provide site-specific engineering to support each well application to ensure that new HVHF designs are safe.

NYSDEC assumes that 1000' vertical separation between the bottom of the protected groundwater zone and the top of the shale zone where HVHF will occur is sufficiently protective, regardless of shale thickness, HVHF job size, and other subsurface characteristics. However, this approach is not technically supported. The 2011 RDSGEIS concludes:

> *As explained in Section 6.1.5.2, the conclusion that harm from fracturing fluid migration up from the horizontal wellbore is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone. The presence of 1,000 feet of low-permeability rocks between the fracture zone and a drinking water source serves as a natural or inherent mitigation measure that protects against groundwater contamination from hydraulic fracturing [emphasis added].*[132]

[130] 2011 NYSDEC, RDSGEIS, Page 7-59.

[131] Fontaine, J., and Johnson, N. (Universal Well Services), and Schoen, D. (Guardian Exploration), Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper, SPE 117772, 2008, Page 11.

[132] 2011 NYSDEC, RDSGEIS, Page 7-59.

Neither the 2009 DSGEIS nor the 2011 RDSGEIS contain site-specific NYS Marcellus Shale hydraulic fracture model data to support NYSDEC's conclusion that a 1,000' vertical separation will be protective in all cases in NYS, especially where thinner, shallower shales are present. Furthermore, the 2011 RDSGEIS lacks data on vertical and horizontal fracture propagation in the Marcellus Shale at depths between 2000' and 5000' (depths that NYS proposes to permit).

The behavior of HVHF propagation in NYS is not currently well understood. HCLLC was unable to locate any NYS site-specific hydraulic fracture models for the Marcellus, Utica, or other low-permeability reservoirs. If these models exist, they should be described in the SGEIS, and NYSDEC should explain how it used the data from these models to inform its SGEIS.

Instead, the RDSGEIS currently relies on Marcellus Shale HVHF data from other states that may not be applicable to NYS. For example, NYSDEC points to data collected on 400 Marcellus hydraulic fractures conducted in Pennsylvania, West Virginia, and Ohio. This data was summarized in a three page article in the American Oil & Gas Reporter in July 2010:

> *Four hundred Marcellus hydraulic fracturing stages in Pennsylvania, West Virginia and Ohio have been mapped with respect to vertical growth and distance to the deepest water wells in the corresponding areas. Although many of the hydraulic fracturing stages occurred at depths greater than the depths at which the Marcellus occurs in New York, the results across all depth ranges showed that induced fractures did not approach the depth of drinking water aquifers. In addition, as previously discussed, at the shallow end of the target depth range in New York, fracture growth orientation would change from vertical to horizontal.*[133]

NYSDEC's conclusions rely heavily on the American Oil & Gas Reporter three-page article (Fisher, 2010); yet NYSDEC does not further investigate the origin of the data contained in this article or its implications for shale development in NYS. Fracture growth is a function of type of formations located above and below the Marcellus Shale. Subsurface geology will vary across states and the RDSGEIS does not explain how this data is applicable to NYS. For example, this article:

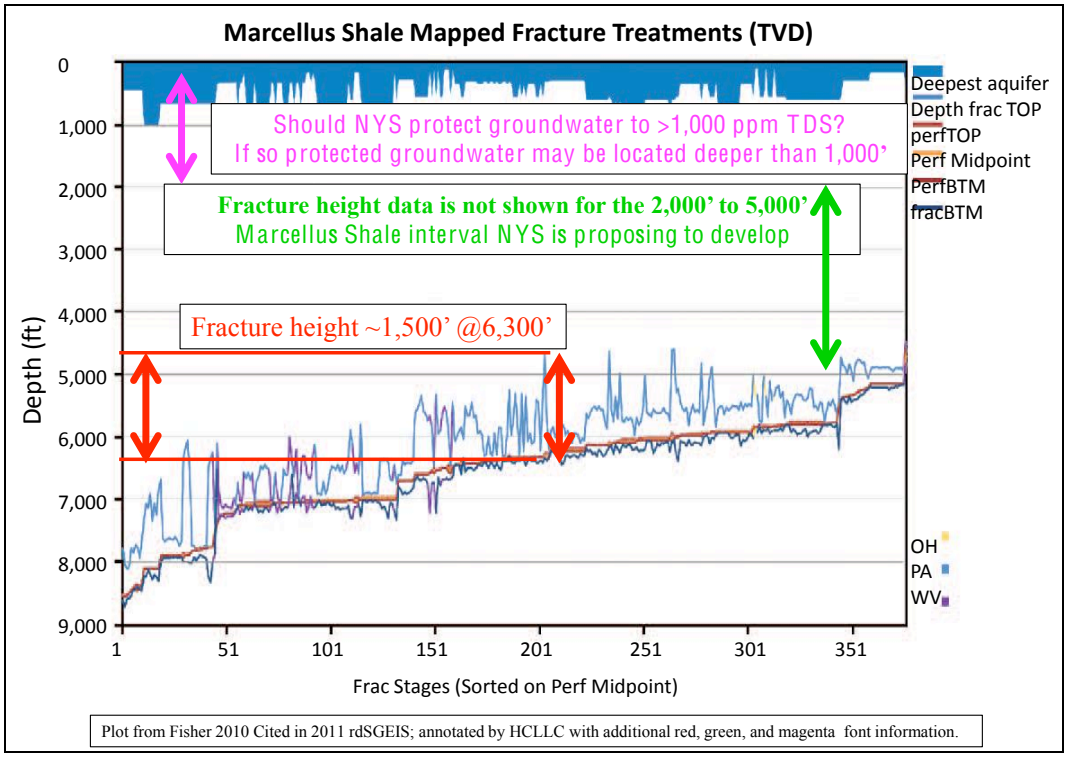
- Does not provide any information on the maximum HVHF job size (volumes, pressures, rates, etc.) to verify whether the fracture treatments conducted and analyzed are equivalent to the maximum HVHF job size anticipated in NYS;
- Does not provide any information on the Marcellus Shale thickness or geophysical properties present during the HVHF treatments;
- Shows that vertical fractures in excess of 1000' were observed (the plot, which is copied from the Fisher 2010 report and provided below, shows a 1500' vertical fracture propagated at 6300');
- Does not show what the vertical fracture growth height would be in the 2000-5000' Marcellus Shale depth interval that NYS proposes to develop; and,
- Does not show the horizontal distance that a fracture will propagate at the shallower shale depths NYS plans to develop.

[133] 2011 NYSDEC, RDSGEIS, Page 6-56.

A more in-depth technical paper written by Kevin Fisher (Halliburton) in 2011 appears to be the origin of the data cited in the American Oil & Gas Reporter article. Fisher's 2011 paper[134] concludes that:

> *Fracture lengths can sometimes exceed a thousand feet when contained with a relatively homogeneous layer [emphasis added].*
>
> *At depths deeper than about 2,000 ft, the vertical stress or overburden is generally the largest single stress so the principal fracture orientation is expected to be vertical on deeper wells [emphasis added].*
>
> *At some point on shallow wells, the overburden stress will decrease to a point where it is less than the maximum horizontal stress and, at this point, one would expect the fracture growth to be horizontal and not vertical. As wells get shallower, and the overburden stress lessens, mapped fractures are typically observed exhibiting increasingly larger horizontal components. All of the fractures do not necessarily turn horizontal; they might have significant vertical and horizontal components with more of a T-shaped geometry, but the horizontal components can become significant and could thieve away enough fluid causing a blunting effect, limiting upward fracture-height growth [emphasis added].*

The Marcellus fracture height figure shown in the American Oil & Gas Reporter is provided below; HCLLC annotated it to identify additional evaluation that is needed for NYS.



The use of vertical offset limits to separate hydrocarbon recovery operations from protected aquifers is a reasonable approach, but it must be scientifically and technical supported. While it is possible that a 1,000' vertical offset may potentially be sufficiently protective; the 2011 RDSGEIS does not provide sufficient scientific data or technical examination to support this recommended threshold.

[134] Fisher, K. and Warpinski, N., Pinnacle- A Halliburton Service, Hydraulic Fracture-Height Growth: Real Data, Society of Petroleum Engineers Paper, SPE 145949, 2011, Pages 1-2 and 5.

In addition to understanding the maximum vertical fracture propagation height, horizontal fracture propagation distance is an important consideration, especially when developing shallower shale zones. Fractures in shallower formations will tend to propagate on the horizontal plane. HVHF treatments should be designed to prevent fractures from intersecting with existing improperly constructed and improperly abandoned wells, and transmissive faults and fractures, which can provide pollutants a direct pathway to protected groundwater resources.

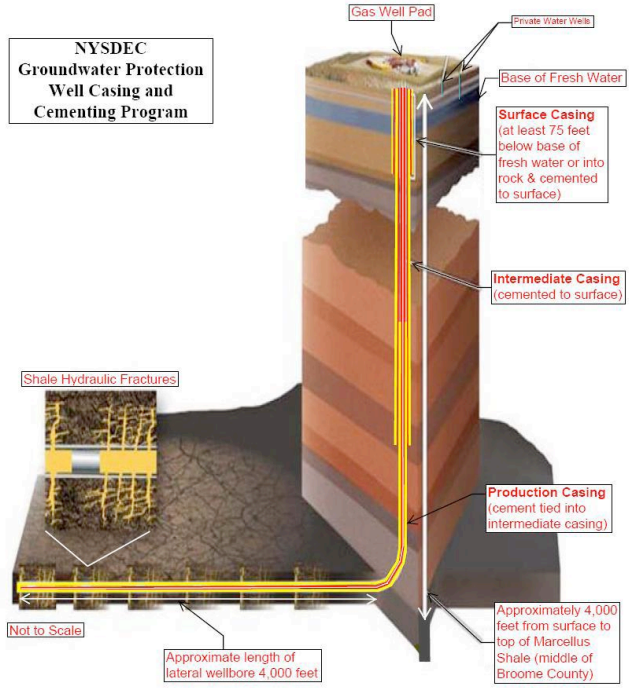
For example, in 2010 the BC Oil & Gas Commission issued a safety advisory on the risks of fracture treatments intersecting adjacent wells. The advisory specifically notified industry that:

> *A large kick was recently taken on a well being horizontally drilled for unconventional gas production in the Montney formation. The kick was caused by a fracturing operation being conducted on an adjacent horizontal well. Fracture sand was **circulated from the drilling wellbore, which was 670m [~2200'] from the wellbore** undergoing the fracturing operation. [emphasis added].*[135]

Additionally, the advisory reported 18 known fracture communication incidents in B.C. and one in Western Alberta: five incidents of fracture stimulation communicating with an adjacent well; three incidents of drilling into a hydraulic fracture formed during a previous stimulation on an adjacent well and containing high pressure fluids; 10 incidents of fracture stimulations communicating into adjacent producing wells, and one incident of fracture stimulations communication into an adjacent leg on the same well for a multi-lateral well. Therefore fracture stimulations communication with adjacent wells is a known and reasonably foreseeable risk.

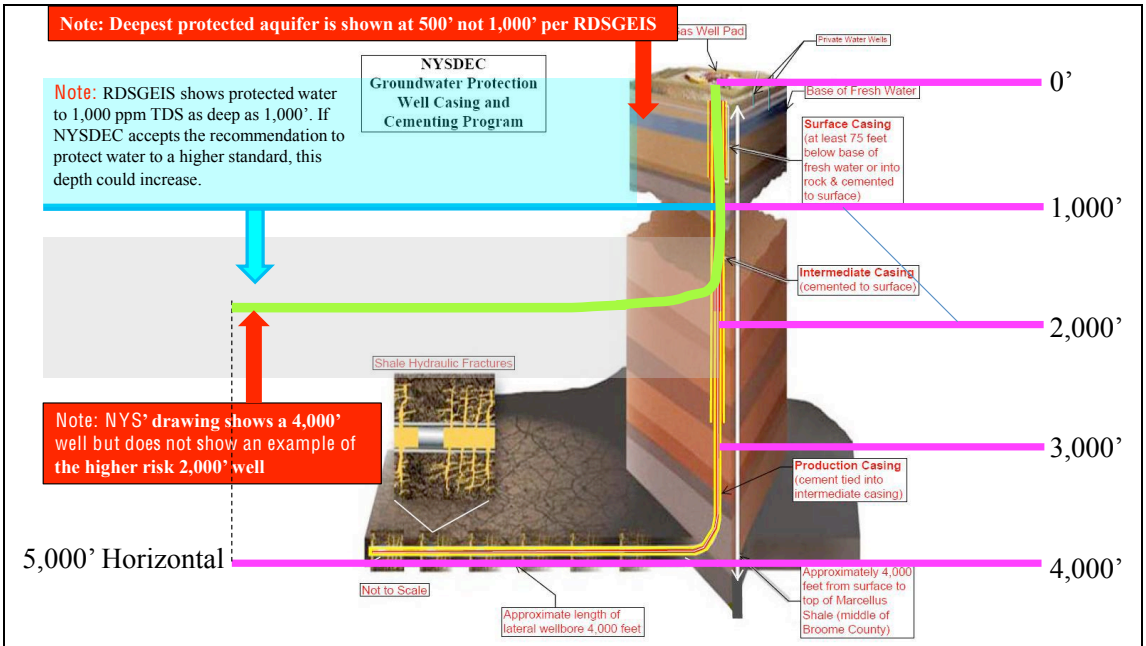
The 2011 RDSGEIS includes a wellbore schematic used in presentations given by the NYSDEC Commissioner. This wellbore schematic, shown below, depicts an example Marcellus Shale well. In the example the base of freshwater is at 500', the well is drilled to a depth of 4,000', and the horizontal length of the well is 4,000'.

[135] BC Oil & Gas Commission, Safety Advisory 2010-03, Communication During Fracture Stimulation, May 20, 2010.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing showing a 500' freshwater depth and a 4,000' HVHF well.

The drawing does not represent the highest risk wells proposed in the 2011 RDSGEIS. The highest risk wells allowed under the 2011 RDSGEIS would be drilled into a thin section of the Marcellus Shale at a 2,000' depth, with protected water located above at 1,000'. Below is an annotated version of this wellbore schematic, prepared by HCLLC, showing the higher risk wells proposed under the RDSGEIS.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing was annotated by HCLLC to show a HVHF well constructed at 2,000' depth, the base of freshwater at least at 1,000' and a theoretical uncertainty zone associated with vertical and horizontal fracture propagation at 2,000' depth.

As explained in Chapter 9 of this report , if a HVHF treatment intersects with a nearby improperly abandoned well, the potential exists for the improperly abandoned well to become a vertical conduit, and therefore transfer hydraulic fluid and mobilized gas to protected aquifers. Additionally, the pollution risk posed by possible HVHF intersections is not limited to improperly abandoned wells; existing wells that were poorly designed and constructed could also pose a risk.

Physics dictate that fractures form perpendicular to the direction of the least amount of stress. Vertical fracture height will decrease with depth, and horizontal fracture length will increase.

NYSDEC proposes that operators identify wells within a mile radius around the surface location of a HVHF well, to identify wells that might be at risk of intersection with HVHF treatments.[136] However, NYSDEC does not provide technical data to support a mile radius. The 2011 RDSGEIS does not specify a maximum horizontal drilling length. Although NYSDEC's spacing rules may impose some limitation on this length, limitations are not clearly explained in the RDSGEIS.

The RDSGEIS should identify the maximum horizontal fracture propagation distance that could occur in a shallow well to ensure that HVHF treatments do not intersect existing wellbores. This should be included in the SGEIS. Limits on horizontal drilling section lengths and HVHF job size, including a safety zone around each HVHF well, should also be established.

> Recommendation No. 34: The SGEIS should provide a basis for the maximum horizontal well drilling limit. The SGEIS should also explain how the operator will verify that the maximum horizontal well drilling limit, plus the maximum predicted horizontal fracture length, will avoid nearby well intersection.

The most logical way forward is to begin by limiting development to the deepest Marcellus Shale intervals, maximizing the vertical separation from drinking water aquifers. Once accurate, field-calibrated 3D reservoir simulation models are available for NYS, development can then move to shallower intervals, as long as technical data shows that treatments will remain in zone.

> Recommendation No. 35: The SGEIS should technically justify vertical and horizontal HVHF treatment offsets. Proposed offsets should be supported by hydraulic fracture modeling. Modeling should reflect the maximum HVHF job designs allowed in NYS and shale reservoir characteristics. NYSDEC should provide public access to the scientific data and hydraulic fracture models it uses to develop vertical and horizontal offsets for the purposes of the SGEIS.

Drilling into the deepest, thickest Marcellus Shale intervals (e.g., below 4000') will maximize data collection, affording access to all overlying intervals. Core samples, well logs, and pressure transient data can be obtained, verifying whether there are continuous permeability barriers hydraulically separating the Marcellus Shale and the overlying drinking water aquifers, and geologic barriers that will limit fracture propagation. Initially, smaller fracture treatments should be used as tests. These treatments can be increased in size over time, if data support the conclusion that large fracture treatments can remain in zone. As data are collected, and 3D reservoir models are developed and refined, it may be possible to safely develop the Marcellus at shallower depths and in thinner intervals.

NYSDEC's recommendation to move forward with shale gas development, absent additional engineering data and hydraulic fracture models, is technically unsupported and in direct conflict with the information cited in its 2009 DSGEIS and 2011 RDSGEIS, as well as its own consultants' recommendations.

[136] 2011 NYSDEC, RDSGEIS, Page 6-56.

Recommendation No. 36: The SGEIS should include a more thorough examination of hydraulic fracture modeling. The SGEIS and NYCRR should require the operator to:

(a) Collect additional geophysical and reservoir data to support a reservoir simulation model;

(b) Develop a high-quality Marcellus Shale 3D reservoir model(s) to safely design fracture treatments;

(c) Maintain and run hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone;

(d) Collect and carefully analyze data from HVHF treatments to optimize future HVHF treatments;

(e) Initially complete HVHF treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience before proceeding to shallower zones (e.g. 4000' deep and 150' thick, progressively moving shallower as more NYS site-specific information is collected); and

(f) Conduct post-fracture analysis, and provide that analysis to NYS to demonstrate that the HVHF treatment was safely implemented.

NYCRR Proposed Revisions: There are no proposed revisions in the NYCRR. As proposed, the NYCRR do not require operators to:

(a) Submit a HVHF designs to NYS;

(b) Estimate the vertical and horizontal fracture length;

(c) Provide engineering analysis and run HVHF modeling;

(d) Monitor HVHF performance to ensure that HVHF design and actual implementation in the field match; and

(e) Notify NYSDEC if the actual vertical and/or horizontal fracture length greatly exceeds the job design, such that risk may be present to the environment.

11. Hydraulic Fracture Treatment Additive Limitations

Background: In 2009, HCLLC recommended that NYS regulations identify fracture treatment additives that are protective of human health and the environment. HCLLC also recommended that the NYCRR include a list of prohibited chemical additives.

2011 RDSGEIS: The 2011 RDSGEIS includes improvements in the handling and storage of HVHF chemicals by requiring chemicals to be stored in suitable containers placed in secondary containment. Additionally, NYSDEC encourages operators to select the lowest toxicity chemicals. However, neither the 2011 RDSGEIS nor the proposed NYCRR amendments establish a prohibited chemical list, nor do they require an operator to use the lowest toxicity chemicals. Instead, the 2011 RDSGEIS requires only that the operator evaluate alternative products. Ultimately, the operator is allowed to select the final chemicals used with no firm evaluation criteria listed in the NYCRR to rule out harmful chemicals.

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.3(c)(1)(v) require only that the operator provide:

> *Documentation that proposed chemical additives exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment than available alternatives; or documentation that available alternative products are not equally effective or feasible.*

The proposed regulation requires the operator to examine chemicals that "exhibit reduced aquatic toxicity" and a "lower risk to water resources," but the NYCRR does not provide specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk.

The 2011 RDSGEIS guides the operator to conduct a five-part analysis:

> *The evaluation criteria should include (1) impact to the environment caused by the additive product if it remains in the environment, (2) the toxicity and mobility of the available alternatives, (3) persistence in the environment, (4) effectiveness of the available alternative to achieve desired results in the engineered fluid system, and (5) feasibility of implementing the alternative.*[137]

However the 2011 RDSGEIS does not instruct the operator on what is required if any part of the five-part analysis has an unacceptable outcome, nor does the NYCRR. For example, if an operator proposes a chemical additive that is known to impact the environment and be persistent if it remains in the environment, but the operator proposes no other alternative, or states that this is the only chemical that will be effective for its planned job, neither the RDSGEIS or the NYCRR prohibit the operator from using this chemical even if it is harmful.

As proposed, the NYCRR would still allow the use of a highly toxic chemical, as long as it was slightly less toxic than the most toxic chemical available. This is not best practice. Best practice would be to use the chemical with the lowest impact and risk, not just a slightly improved risk. Best practice would also be for NYS to develop a list of prohibited chemicals that pose an unacceptable risk to human health and the environment.

[137] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS concludes that it is not possible for hydraulic fracturing to contaminate groundwater, erroneously assuming that all wells will be flawlessly constructed and operated, and that no human error is possible that would put hydraulic fracturing additives in contact with groundwater, with the exception of a potential surface spill. The 2011 RDSGEIS concludes:

> *The regulatory discussion in Section 8.4 concludes that adequate well design prevents contact between fracturing fluids and fresh ground water sources, and text in Chapter 6 along with Appendix 11 on subsurface fluid mobility explain why ground water contamination by migration of fracturing fluid is not a reasonably foreseeable impact.*[138]

The 2011 RDSGEIS should be revised to clarify that groundwater contamination by hydraulic fracturing fluids is a reasonably foreseeable impact that requires mitigation. Well construction failures, engineering design flaws, human error, mechanical malfunctions, and chemical spills all are reasonably foreseeable events, and have occurred at Marcellus Shale operations in Pennsylvania.[139] Additionally, Dr. Myers identifies the potential long-term contaminant transport through conductive faults, natural fractures, and advective transport.[140]

Groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[141] PADEP inspectors *"...discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County."*[142] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[143]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[144]

In May 2011, PADEP fined Chesapeake Energy Corporation $1,088,000 for violations related to natural gas drilling activities that contaminated private water supplies in Bradford County. PADEP issued a news release reporting:

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[138] 2011 NYSDEC, RDSGEIS, Page 8-29.

[139] DEP Investigating Lycoming County Fracking Fluid Spill at XTO Energy Marcellus Well, November 22, 2010, available at http://www.portal. state.pa.us/portal/server.pt/community/newsroom/

14287?id=15315&typeid=1

[140] Dr. Tom Myers, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

[141] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[142] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[143] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[144] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

> *DEP determined that because of improper well casing and cementing in shallow zones, natural gas from non-shale shallow gas formations had experienced localized migration into groundwater and contaminated 16 families' drinking water supplies.*[145]

If HVHF treatments are conducted in poorly constructed wells, there exists a potential for groundwater contamination. Therefore, as NYSDEC recommends, well construction must be robust, and the use of safe HVHF treatment additives provides any extra layer of protection in the event that human error or mechanical malfunction create a pathway for such additives to reach groundwater. Reducing the toxicity of hydraulic fracturing additives by listing prohibited additives mitigates the impact of both surface and groundwater pollution if it occurs.

Recommendation No. 37: NYSDEC should develop a list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2009 DSGEIS Section 5.3[146] stated that NYSDEC collected compositional information from chemical suppliers and service companies on many of the additives proposed for use in shale fracture treatments. NYSDEC reported partial compositional data on 197 products and complete compositional data on 152 products. Tables 5.3-5.7 provided lists of chemicals proposed for use in fracture treatments, and Section 5.4.3.1 described the potential health impacts of categories of chemicals. Yet the 2009 DSGEIS did not arrive at any recommendation or conclusion about which fracture treatment additives are acceptable for use in NYS and which are not. This problem persists in the 2011 RDSGEIS.

Chapter 5 of the 2011 RDSGEIS explains that NYSDOH reviewed information on 322 unique chemicals present in 235 products proposed for hydraulic fracturing of shale formations in New York and categorized them into chemical classes, but did not develop any recommendations for prohibiting specific HF additives. The 2011 RDSGEIS merely concludes that the 322 unique chemicals studied did not identify any potential exposure situations that are qualitatively different from those addressed in the 1992 GEIS.[147] This conclusion has little significance, since the 1992 GEIS did not establish any criteria for limiting or prohibiting HF chemical additives (i.e., for mitigating potential significant adverse impacts from exposure to these additives). For example, Dr. Miller points out that acrylonitrile and acrylamide are listed, and known to be carcinogenic and quite toxic, but fairly short lived in an aqueous environment.[148] As proposed, NYSDEC would allow these carcinogenic, toxic chemicals to be used, unless industry proposes a less-harmful chemical. The appropriate step for NYS would be to add acrylonitrile and acrylamide, among other chemical that pose a risk to human health or the environment, to the list of prohibited chemicals in NYS.

[145] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[146] 2009 NYSDEC, DSGEIS, Page 5-34.

[147] 2011 NYSDEC, RDSGEIS, Page 8-29.

[148] Dr. Glenn Miller, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

Although the percentage of hydraulic fracturing fluid that is composed of chemicals may be small—typically 0.5 to 2 percent of the total volume required for a Marcellus Shale hydraulic fracture stimulation—the absolute volume of chemicals used is very large. A typical Marcellus Shale well may require the use of more than five million gallons of freshwater for drilling and hydraulic fracturing. A five million gallon hydraulic fracture treatment would require approximately 25,000 to 100,000 gallons of hydraulic fracturing chemicals per well at a chemical additive dosage of 0.5 to 2 percent. Some of these chemicals are toxic, including known or possible human carcinogens, chemicals regulated under the Safe Drinking Water Act due to their risks to human health, and chemicals regulated under the Clean Air Act as hazardous air pollutants.[149]

Recommendation No. 38: The SGEIS should do more than just list chemicals proposed by industry for HVHF operations and describe their toxicity; the SGEIS should identify chemicals that should be prohibited or used with limitations to protect human health and the environment.

Additionally, the 2011 RDSGEIS includes a process for reviewing chemicals proposed by industry that appears to have little value or scientific rigor.

> *For every well permit application the Department would require, as part of the EAF Addendum, identification of additive products, by product name and purpose/type, and proposed percent by weight of water, proppants and each additive. This would allow the Department to determine whether the proposed fracturing fluid is water-based and generally similar to the fluid represented by Figures 5.3, 5.4, and 5.5.*[150]

Figures 5.3, 5.4, and 5.5 in the 2011 RDSGEIS are merely pie charts showing example compositions from previous Fayetteville and Marcellus Shale HVHF jobs. The 2011 RDSGEIS does not include a scientific analysis of the proposed HVHF compositions to verify if these mixtures are optimal. Therefore, there is little scientific value in having NYSDEC staff compare an operator's proposed HVHF composition to these figures, because NYSDEC has not even completed the fundamental scientific analysis to verify whether these proposed treatment compositions are protective of human health and the environment and whether the figures are a suitable yardstick.

The 2011 RDSGEIS proposes to require industry to submit a Material Safety Data Sheet (MSDS) for every new product that is not currently listed by NYSDEC in Chapter 5 of the 2011 RDSGEIS. NYSDEC explains that the MSDS will provide it with more information on the proposed chemical, but does not institute a plan for taking action to limit or prohibit hazardous chemical use based on a review of that MSDS. Instead, the 2011 RDSGEIS appears to propose that NYSDEC will just collect MSDS information and take no action, other than to accept the chemicals selected by the operator and add the MSDS to NYSDEC's file system.

> *The Department would also require the submittal of an MSDS for every additive product proposed for use, unless the MSDS for a particular product is already on file as a result of the disclosure provided during the preparation process of this SGEIS (as discussed in Chapter 5) or during the application process for a previous well permit. Submittal of product MSDSs would provide the Department with the identities, properties and effects of the hazardous chemical constituents within each additive proposed for use.*[151]

[149] United States House of Representatives, Committee on Energy and Commerce, Minority Staff, Chemicals Used in Hydraulic Fracturing, April 2011.

[150] 2011 NYSDEC, RDSGEIS, Page 8-30.

[151] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS goes on to say that NYSDEC staff will verify, by reviewing the well completion form, that the chemicals proposed by industry in a permit application (with no limitations or prohibitions by NYSDEC) were actually the same chemicals used on the HVHF job.

> *In addition to the above requirements for well permit applications, the Department would continue its practice of requiring hydraulic fracturing information, including identification of materials and volumes of materials utilized, on the well completion report which is required, in accordance with 6 NYCRR §554.7, to be submitted to the Department within 30 days after the completion of any well. This requirement can be utilized by Department staff to verify that only those additive products proposed at the time of application, or subsequently proposed and approved prior to use, were utilized in a given high-volume hydraulic fracturing operation.*[152]

The proposed review process holds little scientific or audit value, since NYSDEC is not limiting chemicals in the initial application. It is insufficient to bind industry to use specific chemicals at the tail end of the permitting process, when industry can propose any chemical for use on the front-end.

However, the proposed chemical audit review process would have great value if NYSDEC limited or prohibited chemical use in the initial application. In that case, a post-HVHF review process would be valuable to verify that prohibited chemicals were not used.

There are several international models in place that NYSDEC could consider using to develop a prohibited chemical list, or to develop an approved list of chemical, or both. Below is a short summary of three models that could be considered: (1) the Oslo-Paris Convention (OSPAR) list of environmentally friendly chemicals (chemicals considered to Pose Little Or No Risk (PLONOR) for the oil and gas industry); (2) Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands; and (3) the Norwegian Pollution Control Authority chemical coding system for the oil and gas industry. These governmental entities prohibit use of chemicals that have harmful characteristics, such as: low biodegradability; high bioaccumulation potential; high acute toxicity; and detrimental mutagenic or reproductive effects.

OSPAR PLONOR: Certain European governmental entities have developed a list of environmentally friendly chemicals. Under the Oslo-Paris Convention (OSPAR)[153] a list of chemicals that were considered to Pose Little Or No Risk (PLONOR) to the marine environment was developed for use in drilling and stimulation treatments. The PLONOR list was initially developed in early 2000 and has been amended several times to add and de-list chemicals. The PLONOR list has been very effective in reducing chemical pollution from offshore operations, and use of the PLONOR list has expanded to onshore oil and gas operations and to other industrial sectors. HCLCC is not recommending that NYS adopt the PLONOR list without review; instead, HCLLC is recommending that NYSDEC consider a process similar to OSPAR's system to develop a list of hydraulic fracturing treatment additives that would pose little or no risk to human health or the environment if the chemicals spilled, leaked, or were improperly disposed, or, in the alternative, consider developing a list of chemicals to be prohibited from use in hydraulic fracturing operations.

[152] 2011 NYSDEC, RDSGEIS, Page 8-31.

[153] The Convention for the Protection of the Marine Environment of the North-East Atlantic (the "OSPAR Convention") was opened for signature at the Ministerial Meeting of the former Oslo and Paris Commissions in Paris on 22 September 1992. The Convention entered into force on 25 March 1998. It has been ratified by Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, Netherlands, Norway, Portugal, Sweden, Switzerland and the United Kingdom and approved by the European Community and Spain.

The OSPAR process is straight forward: the establishment of criteria for inclusion of substances on the PLONOR list. Industry has the burden of proof to provide scientific and technical data to support listing of a chemical as PLONOR—i.e., industry must prove the chemical poses little or no risk. The OSPAR Commission reviews the data and makes the final listing determination. The Commission also can remove chemicals from the PLONOR list if new information comes to light warranting a de-listing. A current list of PLONOR chemicals can be found at the OSPAR website.[154]

C-NLOPB Guidelines: The Canada-Newfoundland and Labrador Offshore Petroleum Board has developed guidelines that industry must follow to select less harmful chemicals used in their offshore oil and gas operations.[155] Industry operators must demonstrate that they have incorporated a chemical selection process in their management system that conforms to the guidelines, and the Board has the ability to audit industry compliance. The guidelines are reviewed at least once every five years to ensure that gains in scientific and technical knowledge are incorporated, and more frequent reviews may be initiated if significant risks are identified. The C-NLOPB Guidelines rely in part on the PLONOR list, but also establish specific requirements for hazard and risk assessment.

The Norwegian Pollution Control Authority has developed a chemical coding system to prohibit use of harmful and toxic chemicals in the Norwegian petroleum industry. The Norwegian Pollution Control Authority system categorizes chemicals by color, using the colors: black, red, yellow and green. Black chemicals are the most hazardous, followed by red, then yellow. Green chemicals are those listed on the PLONOR list.

Black: chemicals on the OSPAR List of Chemicals for Priority Action, chemicals on the Norwegian Pollution Control Authority prioritized list (White Paper No. 21 (2004-2005)), and chemicals in the following categories, characterized by certain ecotoxicological properties:

- Substances that have both a low biodegradability (BOD_{28}<20%) and a high bioaccumulation potential (log P_{OW}•5);
- Substances that have both a low biodegradability (BOD_{28}<20%) and a high acute toxicity (EC_{50} or LC_{50}•10 mg/l); and
- Substances that are detrimental in a mutagenic or reproductive way.

Red: chemicals in the following categories, characterized by certain ecotoxicological properties:

- Inorganic substances that are acutely toxic (EC_{50} or LC_{50}•1 mg/l);
- Organic substances with a low biodegradability (BOD_{28}<20%);
- Substances that meet two of the three following criteria:
  - Biodegradability equivalent to BOD_{28}<60%;
  - Bioaccumulation potential equivalent to log P_{OW}•3 and molecular weight < 700; or
  - Acute toxicity of EC_{50} or LC_{50}•10 mg/l.[156]

[154] OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic, OSPAR List of Substances/Preparations Used and Discharged Offshore Which Are Considered to Pose Little or No Risk to the Environment (PLONOR), Reference Number: 2004-10, 2008 Update, available at: http://www.klif.no/arbeidsomr/petroleum/dokumenter/plonor2008.pdf

[155] The Canada-Newfoundland and Labrador Offshore Petroleum Board, Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands, April 2009, available at http://publications.gc.ca/collections/collection_2009/one-neb/NE23-151-2009E.pdf.

[156] Regulations Relating to Conduct of Activities in the Petroleum Activities (The Activities Regulations), § 56b. The latest update of this list can be found on OSPAR's website under the Offshore Oil and Gas Industry, Decisions, Recommendations and other Agreements.

Green: chemicals on the OSPAR PLONOR list (chemicals considered to Pose Little Or No Risk to the marine environment).

Yellow: chemicals that are not categorized as Green, Black or Red.

Recommendation No. 39: The SGEIS and the NYCRR should include a more rigorous technical and scientific review process to examine newly proposed fracture treatment additives to ensure they are protective of human health and the environment. In addition to a list of prohibited chemicals, NYSDEC should develop a list of recommended/approved fracture treatment additives that have been scientifically and technically reviewed by NYSDEC and NYSDOH and confirmed to pose little or no risk to human health or the environment. This list could be provided to industry for immediate use and would provide industry with a simplified list of chemicals that have already been determined to pose the least risk.

Any chemical not found on this list, or on the list of prohibited chemicals, could be proposed by industry for future use, but would be subject to an in-depth scientific and technical justification and risk assessment review process before being added to the approved chemical list for NYS.

No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment. Industry should bear the burden of proof of demonstrating to NYSDEC and NYSDOH that the chemical is safe. The technical and scientific review and approval process to examine newly proposed fracture treatment additives should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This more rigorous technical and scientific review process should apply to all hydraulic fracture treatments, not just HVHF treatments.

12. Drilling Mud Composition and Disposal

Background: In 2009, HCLLC recommended that the NYCRR be revised to: acknowledge and mitigate drilling mud pollution impacts; minimize drilling waste generation; limit heavy metal and NORM content; and establish best practices for the collection, treatment and disposal of drilling waste.

NYCRR Proposed Revisions: NYSDEC proactively responded to scientific and technical information provided through the public input process, revising the NYCRR to recognize that drilling muds are polluting fluids. NYSDEC removed the existing sentence at 6 NYCRR § 554.1(c)(1) that says "drilling muds are not considered to be polluting fluids." This is an important and positive change in the regulations.

However, additional work is still needed in the proposed amendments to the NYCRR to define what types of drilling muds should be used at various depths in constructing a well. NYCRR should also be amended to include best practices for how those drilling muds should be properly handled and disposed.

In January 2011, NYS consultant, Alpha Geoscience complimented HCLLC for its recommendations on drilling mud composition and disposal and agreed that additional mitigation was warranted. Alpha Geoscience wrote: [157]

> *Harvey Consulting has commented on the need for regulation revisions to specifically address drilling mud and drilling waste. The report states "New York State regulations should be revised to acknowledge and mitigate drilling mud pollution impacts, minimize drilling waste generation, limit heavy metal and NORM (Naturally Occurring Radioactive Material) content, and establish best practices for collection, treatment and disposal of drilling waste.*
>
> *Current NYS regulation 6 NYCRR §554.1(c)(1) states that drilling muds are not considered polluting fluids. The 1992 GEIS allows drill cuttings to be buried onsite, and the dSGEIS does not address the potential impact. Drilling muds commonly contain barite which contains mercury (1-10 ppm) (www.fossil.energy.gov) and may also contain cadmium. NYSDEC has not set limits on the heavy metal content of drilling mud, and New York State regulations do not address how to dispose of drill cuttings containing NORM.*
>
> *Harvey Consulting's recommended best management practice for most applications includes a combination of waste minimization, using low impact additives, collecting waste in a closed-loop system, pumping waste to a cuttings reinjection unit, and disposing the waste into a disposal well by deep well injection. Harvey Consulting suggests NYSDEC should thoroughly analyze each situation and location to develop the best site-specific best management practices.*
>
> *Harvey Consulting's comments concerning the composition and handling of drilling mud and drilling waste appear to have some merit. Per 6 NYCRR §554.1 (C)(1) drilling muds are not considered polluting fluids, however the presence of mercury and cadmium in barite composed drilling muds may be cause for concern given the quantity of drilling mud that would be required to drill each well.*

[157] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 7-9.

> *NYSDEC regulations do not clearly define the treatment or disposal of drilling waste and any best management practices concerning their handling, and/or recycling are not clearly outlined in the dSGEIS as documented by Harvey Consulting. Section 5.13 of the dSGEIS covers waste disposal, however it is general in its scope and does not outline any best management practices concerning the recycling, treatment, or disposal of drilling waste.*
>
> *Harvey Consulting's review recommends that the dSGEIS include best management practices concerning the type and handling of drilling mud and the subsequent waste byproducts. It suggests that NYSDEC should determine which drilling fluid composition and disposal methods are best practices for various scenarios. Alpha agrees that the proposed measures seem reasonable and would serve to protect the public, environment, and the drilling applicant [emphasis added].*

2011 RDSGEIS: The 2011 RDSGEIS explains that drilling operators propose to drill through protected groundwater zones using compressed air or Water-Based Muds (WBM).

> *The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid.*[158]

The use of compressed air and WBM for drilling though the protected groundwater zones is best practice, as long as NYCRR also sets limits on the type of additives that can be mixed in the WBM formulation. WBM additives used when drilling through the protected groundwater zones should be non-toxic.

The 2011 RDSGEIS' use of the term "typically" indicates that use of compressed air and WBM for drilling though the protected groundwater zones may only occur a portion of the time. This is a best practice that should be implemented each time a well is drilled through protected groundwater zones.

While the 2011 RDSGEIS documents industry's position that it "typically" will use compressed air and WBM for the protection of groundwater, NYSDEC should *require* that practice and ensure that the requirement is codified in NYCRR. The proposed amendments to the NYCRR do not limit the types of drilling muds that can be used while drilling through protected groundwater zones. NYCRR should be revised to clearly prohibit the use of Oil-Based Muds (OBM) and Synthetic-Based Muds (SBM) drilling through protected groundwater zones and to limit additives used in the WBM to those that are non-toxic.

OBM contain diesel fuel or other hydrocarbons. SBM use synthetic oil. SBM are less harmful than OBM, but still contain materials that are toxic, bio-accumulate when discharged into water, and do not bio-degrade. For example, European nations prohibit the discharge of SBM to offshore waters, and prohibit their use when drilling through protected waters.[159] SBM are not approved by USEPA or Department of Energy for discharge offshore because they exceed USEPA's effluent limit guidelines.[160] The 2011 RDSGEIS incorrectly describes SBM as *"food-grade"* and *"environmentally friendly."*[161]

[158] 2011 NYSDEC, RDSGEIS, Page 5-32.

[159] Jonathan Wills, M.A., Ph.D., M.Inst.Pet., for Ekologicheskaya Vahkta Sakhalina, Muddied Waters A Survey of Offshore Oilfield Drilling Wastes and Disposal Techniques to Reduce the Ecological Impact of Sea Dumping, May 25, 2000.

[160] http://web.ead.anl.gov/dwm/techdesc/discharge/index.cfm.

[161] 2011 NYSDEC, RDSGEIS, Page 5-32.

Recommendation No. 40: 6 NYCRR § 554.1(c)(1) should be revised to limit the types of drilling muds that can be used while drilling through subsurface formations that contain protected groundwater. Drilling muds should be limited to Water-Based Muds (WBM) or drilling with air. Any additives required for safe drilling through the protected groundwater interval with WBM should be limited to additives that are bio-degradable, are non-toxic, and do not bio-accumulate. The SGEIS should also include this requirement as a mitigating measure.

Neither the 2011 RDSGEIS nor the proposed amendments to the NYCRR instruct the operator on how to properly dispose of drilling fluids. NYCRR requires a disposal plan and that drilling fluids be removed from the drillsite within 45 days; however, 6 NYCRR § 554.1(c)(1) does not provide specific instructions or criteria for acceptable drilling mud disposal plans. This problem was identified by HCLLC in 2009, and is still unresolved.

This problem is magnified in light of new language in the 2011 RDSGEIS that appears to contemplate allowing drilling muds to be spread on non-active agricultural fields and other soils. The 2011 RDSGEIS includes a discussion on proposed Agricultural District requirements. One of the requirements discussed is for "spent drilling muds to be removed from active agricultural fields."[162] The RDSGEIS is silent on provisions for non-active agricultural fields and other soils, and it is unclear what NYSDEC has planned for drilling mud disposal. NYSDEC should clarify its intentions in regards to spreading drilling muds.

The 2011 RDSGEIS correctly notes that drilling mud can be reconditioned and used at more than one well,[163] but it must eventually be disposed. Drilling muds may contain mercury, metals, NORM, oils, and other contaminates. This is especially true for Marcellus Shale operations where naturally occurring radioactive material is present in the shale drill cuttings and mud mixture. Therefore, drilling muds require proper handling and disposal. [164]

Solid waste management regulations at 6 NYCRR Chapter IV, Subchapter B (Solid Waste) provide the authority by which the state (through the Division of Solid and Hazardous Materials) establishes standards and criteria for solid waste management operations, including landfills and land application. However, the RDSGEIS is unclear on what NYSDEC has deemed to be the best management practices for handling drilling waste. A recent U.S. Department of Energy review of NYSDEC's drilling waste disposal regulations concluded:

> *"The [NYS] DEC has developed no regulations, policies, or guidelines governing slurry injection, subsurface injection, or annular disposal of drilling wastes and reserve-pit wastes [emphasis added]."*[165]

NYSDEC has not established regulations to minimize the generation of drilling waste (e.g. reuse, recycle), or established limits on the heavy metal content of drilling mud additives.

Regulations at 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on drilling fluid handling and disposal. Questions that need to be addressed include: Where will drilling waste be taken for treatment and disposal? What tests will be run to characterize the waste stream for proper handling,

[162] 2011 NYSDEC, RDSGEIS, Page 7-145.

[163] 2011 NYSDEC, RDSGEIS, Page 5-32.

[164] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[165] U.S. Department of Energy, Drilling Waste Management Information System, http://web.ead.anl.gov/dwm/regs/state/newyork/index.cfm.

treatment, and disposal? Does the treatment capacity exist to handle this incremental waste in NYS? If so, where are the treatment facilities located? What types of treatments will be completed? What is the ultimate disposal location for the treatment byproducts?

Recommendation No. 41: 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on the best practices for drilling mud handling and disposal. The SGEIS should also provide specific instructions on the best practices for drilling mud handling and disposal as a mitigating measure. See Chapter 13 of this report for additional recommended disposal solutions.

13. Reserve Pit Use & Drill Cuttings Disposal

Background: In 2009, HCLLC recommended that NYSDEC adopt regulations requiring closed-loop tank systems as best practice, instead of the use of temporary reserve pits to handle and store drill muds and cuttings, unless the operator demonstrates that closed-loop tank systems are not technically feasible. Additionally, HCLLC recommended that if temporary reserve pits are used, NYSDEC should adopt regulations that: require impermeable, chemical resistant liner material; limit the types of chemicals stored to those compatible with the liner material; require wildlife protection design standards; and establish firm removal and restoration requirements when drilling was completed. HCLLC recommended that cuttings not be buried onsite, and that waste be removed from the drilling location and properly disposed at an approved waste disposal facility capable of handling the quantity and type of waste generated.

HCLLC recommended that NYS consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a properly designed, approved subsurface disposal well. Additionally, HCLLC recommended that if reserve pits are determined to be the only technically feasible option for temporary waste storage, that storage of drilling waste be limited to un-contaminated drill cuttings, drilled using compressed air or water based-muds with non-toxic additives.

2011 RDSGEIS: The 2011 RDSGEIS recommends closed-loop tank systems as best practice in some circumstances, but in other circumstances defaults to the use of reserve pits, without demonstrating that reserve pits are environmentally preferable.

The RDSGEIS requires a closed-loop tank system for horizontal drilling operations in the Marcellus Shale that do not have an acceptable acid rock drainage (ARD) mitigation plan[166] for on-site cuttings burial; and drill cuttings that are coated with Synthetic-Based Muds (SBM) and Oil-Based Muds (OBM). In all other cases, the RDSGEIS proposes the use of reserve pits.

> *The revised draft SGEIS proposes to require, pursuant to permit conditions and/or regulation, that a closed-loop tank system be used instead of a reserve pit to manage drilling fluids and cuttings for:*
>
> - *Horizontal drilling in the Marcellus Shale without an acceptable acid rock drainage (ARD) mitigation plan for on-site cuttings burial; and*
> - *cuttings that, because of the drilling fluid composition used must be disposed off-site, including at a landfill.* [167]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 56 requires the operator to provide NYSDEC with an acid rock drainage mitigation plan if NYSDEC requests the plan. However, there is no specific criteria established to define what constitutes and acceptable acid rock drainage mitigation plan.

[166] 2011 NYSDEC, RDSGEIS, Page 7-67.

[167] 2011 NYSDEC, RDSGEIS, Page 1-13.

Yet, the USGS recommends against onsite disposal because of the potential risk posed:

> *Onsite burial of drill cuttings at shale-gas development sites, which is allowable under the dSGEIS if oil-based drilling mud is not used, should be carefully considered. According to Lash and Engelder (2008), pyrite is abundant in the high-TOC basal intervals of the Marcellus Shale. Oxidation and leaching of pyritic shale produces and acidic, metals-rich discharge commonly referred to as AMD (Acid Mine Discharge). A multi-horizontal well site will generate 100 to 500 times the volume of AMD-producing pyritic shale cutting than that generated at a single-vertical well site. If these pyritic shale drill cuttings are left onsite, the potential for future surface-water and groundwater contamination is significant – removal and disposal of all cuttings at an approved landfill would be the preferred approach [emphasis added].*[168]

The RDSGEIS proposal to use reserve pits is internally inconsistent with the RDSGEIS' conclusion that closed-loop tank systems are environmentally preferable for the following reasons:

> *Depending on the configuration and design of a closed-loop tank system use of such a system can offer the following advantages:*
>
> - *Eliminates the time and expense associated with reserve pit construction and reclamation;*
> - *Reduces the surface disturbance associated with the well pad;*
> - *Reduces the amount of water and mud additives required as a result of re-circulation of drilling mud;*
> - *Lowers mud replacement costs by capturing and re-circulating drilling mud;*
> - *Reduces the wastes associated with drilling by separating additional drilling mud from the cuttings; and*
> - *Reduces expenses and truck traffic associated with transporting drilling waste due to the reduced volume of the waste.*[169]

Additionally, the 2011 RDSGEIS explains the environmental risks of reserve pits:

> *Pit leakage or failure could also involve well fluids. These issues are discussed in Chapters 8 and 9 of the 1992 GEIS, but are acknowledged here with respect to unique aspects of the proposed multi-well development method. The conclusions regarding pit construction standards and liner specifications presented in the 1992 GEIS were largely based upon the short duration of a pit's use. The greater intensity and duration of surface activities associated with well pads with multiple wells increases the potential for an accidental spill, pit leak or pit failure if engineering controls and other mitigation measures are not sufficient. Concerns are heightened if on-site pits for*

[168] Testimony of John H. Williams, Ground-Water Specialist, U.S. Geological Survey, The Council of the City of New York Committee on Environmental Protection, Public Hearing, Draft Supplemental Generic Environmental Impact Statement Relating to Drilling for Natural Gas in New York State Using Horizontal Drilling and High-Volume Hydraulic Fracturing, October 23, 2009, Page 2.

[169] 2011 NYSDEC, RDSGEIS, Page 5-39.

> *handling drilling fluids are located in primary and principal aquifer areas, or are constructed on the filled portion of a cut-and-filled well pad [emphasis added].*[170]
>
> *As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be about 40% greater than that for a conventional, vertical well to the same target depth. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad. The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time, unless the cuttings are directed into tanks as part of a closed-loop tank system[emphasis added].*[171]

The use of close-loop drilling waste handling system is a best practice. For example, New Mexico requires the use of closed-loop drilling systems.[172]

Recommendation No. 42: The SGEIS and NYCRR should be revised to prohibit reserve pit use for Marcellus Shale drilling operations, and instead require closed-loop tank systems to collect drill cuttings and transport them to waste disposal facilities. NYCRR should make reserve pit use the exception, allowing it only in cases where closed-loop tank systems are determined to be technically infeasible. If reserve pits are determined to be the only technically feasible option, storage of drilling waste should be limited to un-contaminated drill cuttings from the section of the well drilled using compressed air or water based-muds with non-toxic additives. These best practices for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Of even greater concern is the RDSGEIS' proposal to allow drill cuttings to be buried onsite in some cases. Marcellus Shale cuttings contain Naturally Occurring Radioactive Materials (NORM) and are coated with drilling muds, including Water-Based Mud (WBM). The Marcellus Shale is considered a "highly radioactive" shale,[173] and its drill cuttings may require special hazardous waste handling and treatment. While the RDSGEIS proposes to allow on-site burial only of drill cuttings that were created by air drilling or WBM drilling operations, WBM may contain mercury, metals, and other contaminants.[174]

> *The Department has determined that drill cuttings are solid wastes, specifically construction and demolition debris, under the State's regulatory system. Therefore, the Department would allow disposal of cuttings from drilling processes which utilize only air and/or water on-site, at construction and demolition (C&D) debris landfills, or at municipal solid waste (MSW) landfills, while cuttings from processes which utilize any oil-based or polymer-based products could only be disposed of at MSW landfills [emphasis added].*[175]

[170] 2011 NYSDEC, RDSGEIS, Page 6-16.

[171] 2011 NYSDEC, RDSGEIS, Page 6-65.

[172] New Mexico, Energy, Minerals and Natural Resources Department, Oil Conservation Division, Regulations at Title 19, Chapter 15, Part 17.

[173] Hill, D.G., Lombardi, T.E. and Martin, J.P., Fractured Shale Gas Potential in New York, 2002, p.8.

[174] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[175] 2011 NYSDEC, RDSGEIS, Page 1-13.

The proposed revisions to NYCRR would require the reserve pit liner to be ripped and perforated as part of the onsite burial process (6 NYCRR § 560.7(c)); therefore, contaminated drill cuttings would be in direct contact with soils and surface waters.

While the RDSGEIS generally takes the position that WBM-coated cuttings can be stored in reserve pits and buried onsite, in some cases it waivers. It is not clear what additional limitations may be applied to WBM-coated drill-cuttings disposal. NYSDEC recognizes that onsite burial of chemical additives included in WBM may not be prudent. However, the RDSGEIS does not spell out criteria for determining what types of WBM-coated cuttings may and may not be stored and buried in reserve pits. The RDSGEIS proposes this decision be left to a later NYSDEC consultation process.

An example of how the RDSGEIS deviates from its general position that WBM-coated cuttings can be stored in reserve pits and buried onsite is as follows:

> *Supplementary permit conditions pertaining to the management of drill cuttings from high-volume hydraulic fracturing* ***require consultation with the Department's Division*** *of Materials Management for the disposal of any cuttings associated with water-based mud-drilling and any pit liner associated with water-based or brine-based mud-drilling where the water-based or brine-based mud contains chemical additives. Supplemental permit conditions also dictate that any cuttings required to be disposed of off-site, including at a landfill, be managed on-site within a closed-loop tank system rather than a reserve pit [emphasis added].*[176]

This uncertain position about what to do with WBM-coated drill cuttings is perpetuated in the proposed revisions to NYCRR at 6 NYCRR § 560.7(c):

> *Consultation with the department's Division of Materials Management (DMM) is required prior to disposal of any cuttings associated with water-based mud-drilling and pit liner associated with water-based mud-drilling where the water-based mud contains chemical additives.*

All WBM contains chemical additives. NYCRR must be clear on which chemical additives would trigger the use of closed-loop tanks and prohibit drill cuttings burial onsite.

> Recommendation No. 43: The SGEIS and NYCRR should be clear about how WBM-coated drill cuttings will be handled and should not leave this unresolved. The standards for handling WBM-coated drill cuttings should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Additionally, it is inefficient from a logistics and energy use standpoint to construct a reserve pit for the temporary storage of drill cuttings, and then remove this pit at a later time. It is substantially more efficient to use a closed-loop tank system to collect the drill cuttings, because the cuttings can be directly transported to a waste handling facility. The RDSGEIS agrees with the efficiencies gained through closed-loop tank systems, but incongruously does not recommend them in all cases.

[176] 2011 NYSDEC, RDSGEIS, Page 7-67.

> *The 1992 GEIS discusses the use of reserve pits and tanks, either alone or in conjunction with one another, to contain the cuttings and fluids associated with the drilling process. Both systems result in complete capture of the fluids and cuttings; however the use of tanks in closed-loop tank systems facilitates off-site disposal of wastes while more efficiently utilizing drilling fluid and providing additional insurance against environmental releases [emphasis added].*[177]

> *The design and configuration of closed-loop tank systems will vary from operator to operator, but all such systems contain drilling fluids and cuttings in a series of containers, thereby eliminating the need for a reserve pit….the objective is to fully contain the cuttings and fluids in such a manner as to prevent direct contact with the ground surface or the need to construct a lined reserve pit.*[178]

NYSDEC's proposal for onsite burial of contaminated drill cuttings becomes even more paradoxical when the RDSGEIS concludes that operators have not proposed onsite burial of drill cuttings.

> *Operators have not proposed on-site burial of mud-drilled cuttings, which would be equivalent to burial or direct ground discharge of the drilling mud itself. Contaminants in the mud or in contact with the liner if buried on-site could adversely impact soil or leach into shallow groundwater [emphasis added].*[179]

A portion of the well drilled will generate cuttings that do not contain NORM. However, as identified in the RDSGEIS, the Marcellus contains NORM and cuttings drilled during this section of the well would require special handling and disposal.

Recommendation No. 44: The SGEIS and NYCRR should prohibit the onsite burial of drill cuttings. If onsite burial is permitted, it should be limited to cuttings that do not have any NORM and are not coated with drill muds containing mercury, heavy metals, and other chemical additives.

Cuttings Reinjection (CRI) Technology, also referred to as "grind-and-inject technology" is commonly used by industry as a best practice to avoid the need for long-term onsite burial of drill cuttings. CRI technology converts drill cuttings into a slurry that can be injected into a subsurface disposal well. CRI also provides a waste disposal method for used drilling mud, because mud can be used in the slurry formulation to reduce supplemental water needs. Currently, NYS does not have sufficient waste disposal wells to handle the anticipated Marcellus Shale drilling waste volume. Either NYS would need to rely on permitted waste handling capacity at wells out of state, or would need to permit and drill wells to meet that need if there are geologically, hydrologically, and otherwise appropriate locations for such wells in NYS.

For example, CRI is commonly used in Alaska as a best practice to avoid use of long-term reserve pit use and surface burial of contaminated drill cuttings. Waste is collected, ground into a slurry, and injected into a subsurface disposal well.[180] If an injection well is not available at a well location, operators have

[177] 2011 NYSDEC, RDSGEIS, Page 5-37.

[178] 2011 NYSDEC, RDSGEIS, Page 5-37.

[179] 2011 NYSDEC, RDSGEIS, Page 6-66.

[180] BP Exploration (Alaska), Inc., ARCO Alaska, Inc. and ConocoPhillips, Inc. have published numerous technical papers on grind and injection technology, and the success of disposal wells as a pollution prevention measure in the SPE trade journals, and at industry conferences.

collected wastes and transported them back to an injection well location. Operators that do not have their own waste handling facilities or disposal wells typically negotiate an agreement with another operator or a service provider to use its disposal facilities. As a result of this best practice implementation in Alaska, DOE reports there are 58 active Class II-D (disposal) wells and six Class I wells in Alaska.[181]

NYS would need to permit construction of a sufficient number of Class I and Class II injection wells to ensure that there was sufficient capacity for the types and amounts of waste generated.

In addition to the environmental mitigation benefit, CRI technology reduces future liability for industry operators, and has been determined to be an environmentally-appropriate method for handling drilling waste containing NORM by both Shell and Chevron.[182]

Halliburton, an industry service provider, agrees that CRI technology makes business and environmental sense as compared to long-term drilling waste burial at the surface.

> *While it is true that new technology comes with a price tag, and much of the technology used in drilling waste management has been introduced in the last 10 years, many technologies now available to operators are clearly cost effective when the entire well construction cost is evaluated.*
>
> *The cost of making a mistake and having either an expensive remediation project or a potential liability nearly always significantly outweighs the cost of a good preventative drilling waste management program. Further, compliance with current environmental regulations does not always guarantee immunity in the future…*
>
> *Numerous examples exist of industries having to clean up sites that were fully compliant with all regulations at the time the waste was generated and disposed of….*
>
> *The paper demonstrates that the correct application of these technologies combined with a holistic approach to drilling waste management and drilling fluid operations results in a net reduction in well construction costs and a reduction in the potential for environmental liability…*
>
> *… environmental compliance (whether internally or externally driven) is not the only reason to utilize these types of technologies and services [emphasis added].*[183]

International operators report favorable economics for eliminating exploration and production waste by deep well injection. For example, a 2001 Advantek International Corp. report concludes:

> *Downhole disposal of mud and cuttings waste through hydraulic fracturing provides a zero discharge solution and eliminates future cleanup liabilities…This downhole disposal technology has shown success in both onshore and offshore drilling operations and is*

[181] Puder, M.G., Bryson, B., Veil, J.A, Argonne National Laboratory, "Compendium of Regulatory Requirements Governing Underground Injection of Drilling Wastes," Prepared for the U.S. Department of Energy, February 2003, Page 17.

[182] Okorodudu, A., Akinbodunse, A., Linden, L., Chevron Nigeria Ltd, Anwuri, L., Shell Petroleum Development Co. Nigeria Ltd., Irrechukwu, D.O., Zagi, M.M., Nigeria Department of Petroleum Resources, Guerrero, H., M-I Swaco, "Feasibility Study of Cuttings-Injection Operation: A Case Study of the Niger Delta Basin," SPE Paper 98640, presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production in Abu Dhabi, U.A.E., April 2006,Page 2.

[183] Browing, K., Seaton, S., Halliburton Fluid Systems, "Drilling Waste Management: Case Histories Demonstrate that Effective Drilling Waste Management Can Reduce Overall Well-Construction Costs," SPE Paper 96775, presented at the 2005 SPE Annual Technical Conference and Exhibition in Dallas Texas, October 2005, Pages 1, 3, & 4

> *becoming a routine disposal option…It also offers favorable economics [emphasis added].*[184]

The U.S. Department of Energy (DOE) also advocates CRI technology:

> *Because wastes are injected deep into the earth below drinking water zones, proper slurry injection operations should pose lower environmental and health risks than more conventional surface disposal methods.*[185]

In 1990, the United States passed the Pollution Prevention Act, establishing a national policy that places priority on pollution prevention and specifies that disposal into the environment should only be allowed as a last resort:

> *The Congress hereby declares it to be the national policy of the United States that pollution should be prevented or reduced at the source whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner whenever feasible; and disposal or other release into the environment should be employed only as a last resort and should be conducted in an environmentally safe manner[emphasis added].*"[186]

Additionally, the amount of drill-cutting waste generated can be significant. If CRI technology is not used to dispose of this waste by deep well injection, than surface waste disposal sites will need to be utilized to handle this waste. The RDSGEIS estimates the amount of waste generated for each well:

> *For example, a vertical well with surface, intermediate and production casing drilled to a total depth of 7,000 feet produces approximately 154 cubic yards of cuttings, while a horizontally drilled well with the same casing program to the same target depth with an example 4,000-foot lateral section produces a total volume of approximately 217 cubic yards of cuttings (i.e., about 40% more). A multi-well site would produce approximately that volume of cuttings from each well.*[187]

Recommendation No. 45: NYS should consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a subsurface disposal well, and work with industry to permit a sufficient number of drilling waste disposal wells to safely meet this need. The use of Cuttings Reinjection (CRI) technology for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR, as an environmentally preferable option to onsite-disposal of drilling waste.

[184] Abou-Sayed, A., SPE, Advantek International, Guo, Q., SPE, Advantek International, "Design Considerations in Drill Cuttings Re-Injection Through Downhole Fracturing," IADC/SPE Paper 72308, Presented at the IADC/SPE Middle East Drilling Technology Meeting in Bahrain, October 2001, Page 1.

[185] Argonne National Laboratory, "An Introduction to Slurry Injection Technology for Disposal of Drilling Wastes," Publication prepared for the U.S. Department of Energy, September 2003, Page 2.

[186] Pollution Prevention Act of 1990, U.S. Code, Title 42, Public Health and Welfare, Chapter 133, Pollution Prevention.

[187] 2011 NYSDEC, RDSGEIS, Page 5-34.

14. HVHF Flowback Surface Impoundments at Drillsite

Background: In 2009, HCLLC recommended that the NYCRR require fracture fluid flowback be routed to onsite treatment systems for fracture fluid recycling and/or collected in closed-loop tanks for transportation to offsite treatment systems. Surface impoundments should not be used for fracture fluid flowback.

2011 RDSGEIS: The 2011 RDSGEIS made excellent revisions that address public concerns and are protective of human health and the environment by clearly prohibiting HVHF flowback waste impoundments at drillsites. The 2011 RDSGEIS recommends the use of closed-loop tank systems at the drillsites for collecting waste before transporting it to a treatment location, or recycling it for use on another well:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[188]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[189]

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.6(c)(27) specifically prohibit HVHF flowback from being directed to or stored in any on-site pit, and require covered watertight tanks to handle flowback at the drillsite. Furthermore, 6 NYCRR § 750-3.4(b) prohibits the issuance of a State Pollutant Discharge Elimination System (SPDES) permit without prior certification that HVHF flowback fluids will be not be directed to or stored in a pit or impoundment. Proposed regulations at 6 NYCRR § 560.3(a)(10)-(11) also require an operator to provide a description of the closed-loop tank system it will use and the number of receiving tanks it will employ for flowback water.

No further recommendations. The RDSGEIS includes the use of closed-loop tank systems, which is best available technology.

[188] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[189] 2011 NYSDEC, RDSGEIS, Page 1-12.

15. HVHF Flowback Centralized Surface Impoundments Off-Drillsite

Background: In 2009, HCLLC recommended that the NYCRR prohibit the use of centralized surface impoundments for HVHF flowback. This recommendation was made because it is best technology to eliminate the use of surface impoundments altogether, rather than gathering HVHF flowback into tanks at the drillsite and then moving it by pipeline or truck to be pumped into a larger open impoundment at a centralized location away from drillsites. If flowback is recycled, it should be trucked or piped from tank–to–tank to another drillsite or used at the same drillsite in a different well.

Eliminating use of centralized surface impoundments prevents: large scale surface disturbance that requires multi-year rehabilitation[190]; the potential for leakage to occur through or around the liner, impacting ground water; and the potential to generate substantial amounts of hazardous air pollution.

A centralized surface impoundment photograph in Pennsylvania is shown below.



Bednarski Centralized Waste Impoundment, Pennsylvania, Site Permit PADEP, 798407

The most serious concern with the use of centralized surface impoundments for HVHF flowback is the amount of hazardous air pollution predicted for these centralized surface impoundments. In 2009, NYSDEC estimated that each centralized impoundment would be a major source of hazardous air pollution, emitting more than 32.5 tons of air toxics per year, and it was unclear if NYSDEC's estimate was even a worst-case estimate:

[190] Surface disturbance is less for temporary tanks than impoundments. Impoundments require surface soil excavation and multi-year rehabilitation. Temporary tanks used at the drillsite use existing gravel space already in place for drilling operations rather that impacting new and additional surface terrain away from the drillsite.

> *Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission [estimate] of 32.5 tons (i.e., "**major" quantity of HAP**) is theoretically possible at a central impoundment[191] [emphasis added].*

USEPA classifies a major source of hazardous air pollution as a source that emits more than 25 tons per year. These centralized impoundments have been sited nearby residential homes and community facilities in other states, increasing the amount of hazardous air pollution exposure to nearby humans, including increased exposure to benzene, a known human carcinogen.

In January 2011, NYS' consultant, Alpha Geoscience, complimented HCLLC for its recommendations on flowback impoundments, and supported improved mitigation:

> *Harvey Consulting has thoroughly documented their discussion of surface flowback impoundments and hazardous air pollutants, citing a professional journal article, technical guidance documents, consultant reports, and NYSDEC documents.[192]*

2011 RDSGEIS: The 2011 RDSGEIS states that centralized flowback impoundments are "not contemplated" by industry.[193]

> *The Department was informed in September 2010 that operators would not routinely propose to store flowback water either in reserve pits on the wellpad or in centralized impoundments. Therefore, these practices are not addressed in this revised draft SGEIS and such impoundments would not be approved without site-specific environmental review [emphasis added].[194]*

This industry representation is inconsistent with the actual practice of operators in Pennsylvania. Moreover, neither the RDSGEIS nor the proposed NYCRR amendments prohibit the use of centralized flowback impoundments. This leaves the door open for centralized flowback impoundments to be approved if a site-specific environmental review is conducted.

NYSDEC's requirement to use closed-loop HVHF flowback collection tanks at each drillsite is an efficient collection method, because fluid can be easily transferred to a treatment and disposal location, or taken to another well for reuse. It would not be efficient, or environmentally sound, to collect HVHF waste in a closed-loop flowback tank at the drillsite, and then transfer that waste by temporary piping or truck to a large centralized surface impoundment off of the drillsite location.

Recommendation No. 46: The SGEIS and NYCRR should prohibit the use of centralized surface impoundments for HVHF flowback based on the known impacts examined in the SGEIS process. HVHF flowback waste should be collected at the wellhead and recycled or directly routed to disposal. This prohibition should be described in the SGEIS as a mitigation measure and codified in the NYCRR.

[191] 2009, NYSDEC, DSGEIS, Page 6-56.

[192] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 31.

[193] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15.

[194] 2011 NYSDEC, RDSEGIS, Page 1-2.

If NYSDEC does not prohibit the use of centralized impoundments, the SGEIS should analyze the impacts and propose mitigation to protect public health and the environment. The decision to allow centralized flowback impoundments should not be segmented from the SGEIS just because it is known to create significant impacts. Prohibiting the use of centralized impoundments mitigates that known risk.

16. Repeat HVHF Treatment Life Cycle Impacts

Background: In 2009, HCLLC recommended that the DSGEIS disclose how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. HCLLC pointed out that the 2009 DSGEIS estimated water use and waste volumes based on a single initial fracture treatment and that this approach does not consider the fact that most shale gas wells require multiple fracture treatments.

2011 RDSGEIS: The 2011 RDSGEIS indicates there may be a potential for repeated HVHF treatments over the life of the well.[195] However, the 2011 RDSGEIS does not quantify the number of HVHF treatments possible per well, nor does it estimate the peak or cumulative impact of these HVHF treatments. Therefore the RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several decade long lifecycle.

NYSDEC does acknowledge that, when Marcellus repeat HVHF treatments are conducted, the impact will be equivalent to the initial treatment. However, its impact assessment does not examine the peak or cumulative impacts that may occur:

> *Regardless of how often it occurs, if the high-volume hydraulic fracturing procedure is repeated it will entail the same type and duration of surface activity at the well pad as the initial procedure [emphasis added].*[196]

For example, NYSDEC estimates 1,600 or more wells to be drilled and completed per year,[197] estimating a 30 year development life cycle,[198] for a total of 48,000 wells. NYSDEC estimates each HVHF treatment to use an average 4,200,000 gallons per well,[199] and that approximately 9-35% of HVHF treatment returns to the well and is produced as waste that requires handling, treatment and/or disposal.[200] A single HVHF treatment in each well, over a thirty year period, could yield a total waste load of 18-71 billion gallons. That waste volume could double or triple if two or three fracture treatments are conducted on each well over a several decade period. Assuming at least two fracture treatments, and possibly three may be implemented, the waste volumes would increase substantially, possibly exceeding 200 billion gallons.

NYSDEC acknowledges the fact that repeated HVHF treatments have been required in the Barnett shale, typically within 5 years from the initial HVHF.[201] However, NYSDEC notes:

> *Marcellus operators with whom the Department has discussed this question have stated their expectation that refracturing will be a rare event.*[202]

[195] 2011 NYSDEC, RDSGEIS, Page 6-275.
[196] 2011 NYSDEC, RDSGEIS, Page 5-99.
[197] 2011 NYSDEC, RDSGEIS, Page 2-1.
[198] 2011 NYSDEC, RDSGEIS, Page 6-6.
[199] 2011 NYSDEC, RDSGEIS, Page 6-10.
[200] 2011 NYSDEC, RDSGEIS, Page 5-99.
[201] 2011 NYSDEC, RDSGEIS, Page 5-98.
[202] 2011 NYSDEC, RDSGEIS, Page 5-98.

The information NYDEC gathered from a few Marcellus operators, that concludes Marcellus shale re-fracturing will be "rare", is inconsistent with industry literature.

For example, in 2010 Range Resource published a Society of Petroleum Engineering technical paper that describes two successful horizontal shale re-fracture re-stimulations and explains that Marcellus re-fracture stimulations will be used:

> *Based on the success of horizontal re-fracs in other shale plays, re-fracture stimulations in the Marcellus will be an excellent option to maximize fracture complexity and increase the total effective fracture network. …These re-fracs can be utilized to soften overall field decline in future years…"*[203]

In 2006, Schlumberger, an Oil & Gas Service Company, published a Society of Petroleum Engineering technical paper describing the benefits of re-fracture re-stimulations to increase hydrocarbon production in wells that were initially fractured and where hydrocarbon production had declined to a point that it was economically attractive to repeat the fracture stimulation procedure in that same well:

> *A successful refracturing treatment is one that creates a fracture having higher fracture conductivity and/or penetrating an area of higher pore pressure than the previous fracture.*[204]

Schlumberger explains that re-fracture re-stimulations are likely in wells that have the following characteristics: low productivity relative to other wells with comparable pay; remaining reserves in place; need for fracture reorientation to improve hydrocarbon production; poorly placed initial fracture treatment (e.g. proppant crushing, or proppant flowback, use of incompatible fluids); and reservoir complexity leading to poor hydrocarbon recovery.

A 2010 Apache Corporation, Society of Petroleum Engineering paper, agrees that re-fracture re-stimulations will play an important role in shale stimulation for some time to come. Apache Corporation explains that re-fracture re-stimulations are being used in shale wells to increase gas production, and to make good wells even better gas producers:

> *Refracs of even good wells increased the recovery and re-established near initial production rate. Increasing stimulated reservoir volume should increase both the IP*[205] *and EUR*[206]*. When new areas of the shale are exposed in a refrac, there should also be a gain in reserves (Warpinski, 2008). Increases in stimulated reservoir volume could be accomplished by opening many of the micro-cracks and laminations within the undisturbed matrix blocks in the initial drainage [area] that were left unstimulated by previous fracturing attempts. Re-opening of natural and hydraulic fractures that had closed due to overburden and confining stress created by depletion would re-establish matrix area contact.*[207]

[203] Curry, M., and Maloney, T., Range Resources Corp., Woodroof, R., and Leonard, R. ProTechnics Division of Core Laboratories, Less Sand May Not Be Enough, Society of Petroleum Engineers Technical Paper, SPE 131783, 2010. Page 12.

[204] Moore, L.P., Ramakrishnan, H,, Schlumberger, Restimulation: Candidate Selection Methodologies and Treatment Optimization, Society of Petroleum Engineers Technical Paper, SPE 102681, 2006. Page 1.

[205] IP= Initial Production.

[206] EUR= Expected Ultimate Recovery.

[207] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

Re-fracture re-stimulation has been used widely in the Barnett Shale. Many technical papers report successful re-fracture re-stimulations in the Barnett Shale where improved HVHF slickwater fractures were used as a second treatment after the initial cross-linked gel fracture treatment. While the Marcellus and Utica Shales in NYS will start with improved HVHF slickwater fracture treatments, these treatment methods will continue to improve over time, and like the Barnett, repeat fracture treatments will be required to improve hydrocarbon performance as new and improved fracture treatment design supplants existing technology. Apache Corporation explains:

> *Fracturing technology for shales is constantly improving and refracs may slowly fade from common use as the frac designs for shale wells are optimized. Until optimal fracs are achieved and production engineering is optimized, however, refracs will have a place in shale stimulation [emphasis added].*[208]

Additionally, NYSDEC acknowledges the benefits of re-fracture treatment:

> *Several other reasons may develop to repeat the fracturing procedure at a given well. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary. Refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.* [209]

Recommendation No. 47: The SGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the SGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts.

[208] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

[209] 2011 NYSDEC, RDSGEIS, Page 5-98.

17. Air Pollution Control and Monitoring

Air Quality Impact Assessment Modeling Analysis:

In 2009, AKRF's comments on the 2009 DSGEIS (prepared for NRDC) identified a number of shortcomings in the air quality impact assessment modeling analysis. Notably, that emissions from 10 wells per year and simultaneously operating equipment would produce emission impacts that exceed the NAAQS.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantial amount of new modeling work and a number of operational restrictions and limitations to ensure that NAAQS are not violated. While the RDSGEIS has been significantly improved in this area, some problems with the analysis persist, and some new problems have developed.

The following assumptions used in the air quality impact assessment modeling analysis warrant further review and justification:

- The modeling analysis assumes that a maximum of four wells per drillsite will be drilled each year.[210] However, NYS ECL § 23-0501 requires development of all infill drilling within three years of the first well drilled, and the RDSGEIS envisions the Marcellus Shale gas reservoir will be developed from a multi-well pad for a 640-acre spacing unit, with 40-acre spacing. At 40-acre spacing density, 16 wells would need to be drilled in three years to fill a 640-acre unit, meaning that a maximum of 5-6 wells could possibly be drilled per year. This conflicts with the 4 wells per year (12 wells for three years) assumption and would generate more significant air quality impacts than contemplated by the RDSGEIS.
- Gas compositional data used in the modeling analysis was based on Marcellus Shale gas only. There was no analysis of Utica Shale gas or gas from any other low-permeability gas reservoir.[211] Modeling should be based on a reasonable worst case scenario that includes analysis of all shale formations with development potential, not just the Marcellus Shale, if the SGEIS proposes to cover more reservoirs.
- The modeling analysis assumed that there will be no emissions of criteria pollutants from venting. However, the RDSGEIS proposes to allow gas venting of up to 5 MMscf during any consecutive 12-month period, including sour gas, as long as it is vented at least 30 feet in the air. This allowance undermines the assumption that no criteria pollutants would be emitted during venting.
- The modeling analysis assumes only three days of gas flaring per well. However, the RDSGEIS states that flaring can occur for up to a month in some cases.[212] Therefore, the modeling understates the potential emissions from flaring.

[210] 2011 NYSDEC, RDSGEIS, Page 6-104.

[211] 2011 NYSDEC, RDSGEIS, Page 6-115.

[212] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

- The supplemental 24-hour $PM_{2.5}$ model impacts analysis did not evaluate simultaneous operation of equipment operating on the pad. However, other short-term impact assessment assumed simultaneous operation of one well drilling, one well completion and one well flaring, along with operation of the on-site line heater and off-site compressor for the gas production phase for previously-completed wells.[213] Therefore, the 24-hour $PM_{2.5}$ impact modeling is based on inconsistent assumptions.

- To account for the possibility of simultaneous well operations at nearby pads, a simplified sensitivity analysis was performed in the RDSGEIS to determine the potential contribution of an adjacent pad to the modeled impacts.[214] This modeling assumed a single adjacent pad, located one kilometer away (0.62 miles), with identical equipment and emissions as the modeling target pad.

  The RDSGEIS model only examined the potential for two multi-well drillsites, drilling horizontal wells to be located near each other at a distance of 0.62 miles apart. The modeling analysis assumed that only two drillsites would be operating nearby each other, and that drillsite development in an area would occur in a sequential fashion,[215] which is not always the case (especially when there are multiple operators developing an area).

  The modeling analysis did not evaluate the possibility of more than two multi-well drillsite drilling and completion operations adjacent to each other, nor did it evaluate the possibility of multi-well drillsites operating nearby several single well drilling and completion operations drilled on 40 acre spacing. Nor did the analysis examine the possibility that the surface location of multi-well drillsites could be positioned closer than 0.62 miles apart.

  NYS does not require drillsites to be located over the drilling unit, as long as surface siting approval is authorized. Therefore there is a possibility for drillsites to be located closer than 0.62 miles, a possibility of simultaneous operation of more than two drillsites at a time, and a possibility that more significant overlapping ambient air pollution impacts may occur than modeled. Therefore, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. NYSDEC wither needs to examine all possible concurrent operation impacts, or prohibit the possibility.

- Mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal).

  The RDSGEIS assumes that both light and heavy duty trucks will only travel 20-25 miles[216] one way, yet out-of-state treatment and disposal facilities may be located several hundred miles away. For rural operations, it is unlikely that supplies, equipment, specialty contractors, lodging, and other support equipment and personnel will be located within 20-25 miles of the drillsite.

[213] 2011 NYSDEC, RDSGEIS, Page 6-124.

[214] 2011 NYSDEC, RDSGEIS, Page 6-127.

[215] 2011 NYSDEC, RDSGEIS, Page 6-136.

[216] 2011 NYSDEC, RDSGEIS, Page 6-176.

- The modeling analysis assumes that there will be no simultaneous operations of well drilling and completion equipment on a drillsite. There is a permit requirement prohibiting simultaneous operations;[217] however, this requirement is not codified in the proposed revisions to NYCRR.[218]

Recommendation No. 48: The RDSGEIS air quality impact assessment modeling analysis assumptions warrant additional review and justification. Limitations used in the modeling assumption must all be translated into SGEIS as mitigation measures and codified in the NYCRR to ensure the assumed impacts will not be exceeded. This was done in some cases, but not all. In the cases where modeling assumptions used cannot be justified, modeling revisions will be needed to examine impacts and identify required mitigation, or operational limits set.

Air Quality Monitoring Program:

In 2009, AKRF recommended improved air dispersion modeling and a region-wide emissions analysis. In response, NYSDEC completed a significant amount of additional work on the air quality section of the RDSGEIS. A major conclusion from this work was that there is insufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$. As a result of this lack of data, these impacts were not fully quantified by modeling alone. Furthermore, NYSDEC concluded that ambient air quality monitoring program is needed.

While implementation of a ambient air quality monitoring program, is an important improvement in the RDSGEIS, the proposed program needs further definition, a funding commitment, and a formal industry compliance obligation.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a commitment to implement local and regional air quality monitoring:[219]

> *The Department also developed an air monitoring program to fully address potential for adverse air quality impacts beyond those analyzed in the dSGEIS, which are either not fully known at this time or not verifiable by the assessments to date. The air monitoring plan would help determine and distinguish both the background and drilling related concentrations of pertinent pollutants in the ambient air [emphasis added].*[220]
>
> *The dSGEIS identifies additional mitigation measures designed to ensure that emissions associated with high-volume hydraulic fracturing operations do not result in the exceedance of any NAAQS. In addition, the Department has committed to implement local and regional level air quality monitoring at well pads and surrounding areas [emphasis added].*[221]

[217] 2011 NYSDEC, RDSGEIS, Appendix 10, Attachment A, Condition 2.

[218] 2011 NYSDEC, RDSGEIS, Page 6-115.

[219] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

[220] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 16.

[221] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

Although Section 6.5.4 of the RDSGEIS proposes alternative methods for implementing air quality monitoring, it does not settle on a recommended solution.[222] The RDSGEIS proposes two alternatives: (1) industry-led monitoring with NYSDEC oversight, or (2) NYSDEC monitoring with industry funding. The RDSGEIS identifies NYSDEC monitoring with industry funding as the preferred alternative without making clear how this goal will actually be funded and implemented.

Table 6.24 proposes to: add a single air monitoring trailer and mobile laboratory to monitor ozone, particulate matter, oxides of nitrogen and air toxics; use infrared cameras to monitor gas leaks; and conduct summa canister sampling for BTEX and other VOCs. However, the RDSGEIS does not explain how the addition of a single mobile trailer and lab along with some other intermittent sampling will provide sufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$.

The RDSGEIS did not evaluate the possibility of installing permanent monitoring locations at numerous locations in NYS, with priority in existing non-attainment areas, and areas that will be heavily impacted by shale gas development. Instead, the RDSGEIS only proposes to examine "regional level" monitoring by collecting data at two sites in NYS.[223] This proposal is insufficient because monitoring regional ambient air quality is not possible with the limited data provided by a two-site program, proposed for an unspecified time period.

More information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling.

The obligation to fund the air quality monitoring program needs to be clearly tied to a permit condition requirement—for example, the permit to flare or spud a well should require a contribution to an air quality monitoring fund; such a requirement is not set forth in either Appendix 6 or Appendix 10.

> Recommendation No. 49: The SGEIS should include a more rigorous air monitoring program to achieve NYSDEC's goal of regional and local air pollutant impact monitoring. The proposed program should identify: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

The RDSGEIS acknowledges that air monitoring may identify peak or cumulative air pollution impacts that warrant additional emission controls. For example, NYSDEC has identified that:

> *...the consequences of the increased regional NOx and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions,*

[222] 2011 NYSDEC, RDSGEIS, Page 6-180 through 6-184.

[223] 2011 NYSDEC, RDSGEIS, Page 6-181.

> *including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable.*[224]

However, the RDSGEIS does not explain NYSDEC's plan to collect data, identify the potential for air pollutants to exceed the federal, state or local air pollution control standards, or require these additional emission controls in a timely manner before adverse impacts are realized by humans or the surrounding ecosystem.

Recommendation No. 50: The SGEIS should explain NYSDEC's plan to collect data, identify the potential for pollution problems to exceed the federal, state or local air pollution control standards, and the timely installation of additional emission controls, in order to protect against exceedances of pollution control standards, should be required as an SGEIS mitigation measure and codified in the NYCRR.

GHG Impacts Mitigation Plan:

In 2009, HCLLC and AKRF recommended further analysis of Greenhouse Gas (GHG) impacts and mitigation. In response, NYSDEC acknowledged the potential for GHG emissions impacts and the need for mitigation. While such acknowledgement represents a substantial improvement from the 2009 draft, the proposed mitigation needs improvement to ensure the requirements are clear, measureable and enforceable.

The 2011 RDSGEIS: The 2011 RDSGEIS requires a GHG Impacts Mitigation Plan. [225]

> *The Plan must include: a list of best management practices for GHG emission sources for implementation at the permitted well site; a leak detection and repair program; use of EPA's Natural Gas Star best management practices for any pertinent equipment; use of reduced emission completions that provide for the recovery of methane instead of flaring whenever a gas sales line and interconnecting gathering line are available; and a statement that the operator would provide the Department with a copy of the report filed with EPA to meet the GHG Reporting Rule.*[226]

The GHG Impacts Mitigation Plan requires the operator to implement a Leak Detection and Repair Program,[227] use Reduced Emission Completions,[228] use EPA Natural Gas STAR program recommendations, and identify other best management practices.

The requirement that a GHG Impacts Mitigation Plan be prepared and include the use of best management practices for GHG control is a step in the right direction; however, given the variety of best management practices under EPA's voluntary Natural Gas STAR program, NYSDEC should require that well operators select and install the controls that will achieve the greatest emissions reductions possible. In addition, such emissions reductions should be made enforceable, as permit conditions or in the NYCRR.

[224] 2011 NYSDEC, RDSGEIS, Page 6-181.

[225] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[226] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[227] See also HCLLC recommendations on LDAR Program in this section of the report.

[228] See also HCLLC recommendations on Reduced Emission Completions in this section of the report.

For example, the Natural Gas STAR Program data shows that it is both technically feasible and economically attractive to use "low-bleed" or "no-bleed pneumatic controllers and plunger lift systems;[229] however, it is not clear whether an operator would be required under the GHG Impacts Mitigation Plan to use this technology, or how NYSDEC would enforce its use if an operator chose not to select it.

NYSDEC should require operators to use Natural Gas STAR Program best management technologies and practices that will optimize emissions reductions.

The RDSGEIS does not make clear whether or how new technologies or practices would be required (e.g. technologies or practices identified by the Natural Gas STAR Program after drillsite construction has been completed). It is not clear if an operator will be required to implement GHG emission controls only at the time of construction, or if there will be an ongoing obligation to implement additional controls as they are identified by the Natural Gas STAR Program and developed.

The plan should include a list of emission controls that will be installed at the time of construction and best management practices, and a process for periodically reviewing new technologies and installing them as new control solutions are developed over time.

Recommendation No. 51: NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions.

The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs.

The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Flare and Venting of Gas Emissions:

In 2009, HCLLC recommended that flaring and venting be limited to the lowest level technically feasible and safe. Reducing gas flaring and venting is widely considered best practice. Both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[230] Initially the motive was to conserve hydrocarbon resources to maximize federal and

[229] Older gas wells stop flowing when liquids (water and condensate) accumulate inside the wellbore creating backpressure on the hydrocarbon formation. This will be a future problem in NYS, as gas wells age. Methane gas is emitted when companies open wells to vent gas to the atmosphere to unload wellbore liquids (water and condensate that accumulate in the bottom of the well) in order to resume gas flow. The industry typically refers to this process as "blowing down the well" or a "well blowdown." Eventually, even a well's own gas pressure becomes insufficient to flow accumulated liquids to the surface and the well is either shut-in as uneconomic, or some form of artificial lift (e.g. plunger lifts) is installed to transport the liquids to the surface.

[230] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

state revenue and gas supply. More recently, focus on GHG, VOC and HAPs emission reduction has prompted additional innovation to further reduce flaring and venting.

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. If gas processing equipment and pipeline systems are in place, gas flaring can be avoided in all cases except in the event of equipment malfunction. During the drilling and completion phase of the first well on a well pad, a gas pipeline might not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply has been found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to which it can be routed. The RDSGEIS proposes to require Reduced Emission Completions for all wells where a pipeline is installed, which will reduce the need to flare or vent gas.

During production operations, high pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams[231] and gaseous by-product streams[232] that are uneconomical to conserve. Venting or flaring may also occur during manual or instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and pipeline repair.[233]

Best practices for planned[234] flaring and venting during gas production should limit flaring and venting to the smallest amount possible and only for purposes of for safety. Gas should be collected for sale, and used as fuel unless it is proven to be technically and economically unfeasible.

The 2011 RDSGEIS: The 2011 RDSGEIS limits planned gas flaring to flowback operations for wells where a gas sales line has not been installed which is a significant improvement.[235]

However, when flaring or venting does occur, there is the potential for relatively high short-term VOC and CO emission impacts that need to be considered.[236] The RDSGEIS states that industry only plans to flare for a maximum of three days, and NYSDEC only modeled a 3-day impact; yet, the RDSGEIS states that flaring can occur for up to a month (30 days) in some cases. [237]

> *A flaring period of 3 days was considered for this analysis for the vertical and horizontal wells respectively although the actual period could be either shorter or longer [emphasis added].*[238]

Modeling needs to represent a reasonable worst case scenario. Because only a three day flaring period was considered in the RDSGEIS modeling, planned flaring should be limited to no more than three days.

[231] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.

[232] For example: instrument vent gas; stabilizer overheads and process flash gas.

[233] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[234] There is a difference between planned flaring and emergency flaring. Emergency flaring is conducted to safely route combustible and potentially toxic (e.g. hydrogen sulfide gas) and in most cases cannot be avoided. Planned flaring can be avoided in most cases.

[235] 2011 NYSDEC, RDSGEIS, Page 5-135.

[236] 2011 NYSDEC, RDSGEIS, Page 6-103.

[237] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

[238] 2011 NYSDEC, RDSGEIS, Page 6-197.

Alternatively, modeling analysis should be based on the maximum time period that flaring would be allowed.

> Recommendation No. 52: Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. Flaring restrictions should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces HAP, VOC, and GHG emissions.[239] Proposed revisions to 6 NYCRR § 560.6(c)(28) would require that gas be flared whenever technically feasible instead of vented,[240] which is a significant improvement.

The RDSGEIS limits the amount of flaring and venting that is allowed at a drillsite during any consecutive 12-month period; however, it is unclear how the venting (5 MMscf) or flaring (120 MMscf) thresholds were developed, and such thresholds are not listed in the proposed revisions to the NYCRR.

- *During the flowback phase, the venting of gas from each well pad will be limited to a maximum of 5 MMscf during any consecutive 12-month period. If "sour" gas is encountered with detected hydrogen sulfide emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m);*
- *During the flowback phase, flaring of gas at each well pad will be limited to a maximum of 120 MMscf during any consecutive 12-month period [emphasis added].*[241]

> Recommendation No. 53: The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting limits, once justified, should be included in the SGEIS as a mitigation measure, codified in the NYCRR, and should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC require that well operators follow best practices for construction and operation of flares used for safety. The RDSGEIS requires self-igniting flares,[242] which is an improvement; however, the RDSGEIS does not require that:

- Flare pilot blowout risk be minimized by installing a reliable flare system;
- Low/intermittent velocity flare streams have sufficient exit velocity or wind guards;
- A reliable ignition system is used;

[239] Fugitive and Vented methane has 21 times the global warming potential as combusted methane gas. Methanetomarkets.org, epa.gov/gasstar.

[240] 2011 NYSDEC, RDSGEIS, Page 7-117.

[241] 2011 NYSDEC, RDSGEIS, Page 7-108.

[242] 2011 NYSDEC, RDSGEIS, Page 7-117.

- Liquid carry over and entrainment in the gas flare stream is minimized by ensuring a suitable liquid separation system is in place; or
- Combustion efficiency is maximized by proper control and optimization of flare fuel/air/steam flow rates.

Recommendation No. 54: The SGEIS should require flare systems to be designed in a manner that optimizes reliability, safety, and combustion efficiency, including requirements to: minimize the risk of flare pilot blowout by installing a reliable flare system; ensure sufficient exit velocity or provide wind guards for low/intermittent velocity flare streams; ensure use of a reliable ignition system; minimize liquid carry over and entrainment in the gas flare stream by ensuring a suitable liquid separation system is in place; and maximize combustion efficiency by proper control and optimization of flare fuel/air/steam flow rates. Flare design requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

Reduced Emission Completions:

In 2009, HCLLC recommended the use of Reduced Emission Completions (RECs, also known as "green completions") to control methane and other greenhouse gas (GHG) emissions following HVHF operations. RECs also reduce nitrogen oxide (NO_x) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere.

EPA estimates that, on average, an REC can capture 7,700 Mcf/well workover for an unconventional gas well. If, for example, 2,000 wells are exempted during the first few years of Marcellus Shale gas development in NYS before pipeline infrastructure is more broadly developed, that could result in 15.3 Bcf (6.2 $MMTCO_2e$) of methane gas vented to the atmosphere.

To put the significance of 15.3 Bcf of methane gas (6.2 $MMTCO_2e$) into perspective, it is equivalent to the GHG emissions from:

- Over 1,100,000 passenger vehicles; or
- The electric use of approximately 700,000 homes for one year; or
- 13,000,000 barrels of oil consumed.[243]

The 2011 RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of well-sites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale.

Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued.

[243] EPA Greenhouse Gas Equivalencies Calculator, http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results

> *Reduced Emissions Completion (REC) would be required whenever a gathering line is already constructed. In addition, two years after issuance of the first permit for high volume hydraulic fracturing, the Department would evaluate whether the number of wells that can be drilled on a pad without REC should be limited [emphasis added].*[244]

NYSDEC should not defer the implementation of this known best practice, because it could result in the exemption of several thousand wells from this control technology requirement, leading to unmitigated air quality impacts from uncontrolled venting. HCLLC agrees that RECs are not an option for single exploration wells with no offset wells or pipeline infrastructure nearby. In addition, RECs may not be possible if well pressure is too low. Regulations should make exceptions only for these situations in which emission control is truly infeasible. However, RECs should be required in all other circumstances.

Once an exploration well is drilled and hydrocarbons are located, additional drilling and well completion operations on that same drillsite should be coordinated with gas line installation, enabling RECs for all subsequent wells. High-volume hydraulic fracturing can be completed at any time after a well is drilled and gas is found. The well can be temporarily suspended, and the HVHF be conducted once a gas line is in place. In a newly explored area, it may be reasonable to drill an exploration well, and conduct a HVHF treatment to test gas productivity before drilling additional production wells. However, once a commercial source of gas is identified and tested with that initial exploration well, there is no reason to vent or flare gas using the HVHF flowback process and test wells prior to a gas line installation.

In natural gas fields, gas from the first well is often flared or vented during drilling and completion activities, because natural gas pipelines are typically not installed until it is confirmed that an economical gas supply has been found. However, once a pipeline is installed, subsequent wells drilled on that same pad would be in a position to implement REC techniques.

Operators often point to the lack of pipeline infrastructure as a primary reason REC may not be possible. However, there are also alternatives to piping methane, such as using it onsite to generate power, re-injecting it to improve well performance, or providing it to local residents as an affordable power supply. Therefore, RECs do not need to rely solely on the installation of a nearby pipeline.

RECs are technically feasible and economically attractive, and are a commercially available emission control option. Appendix 25 of the RDSGEIS, Reduced Emission Completions Executive Summary, summarizes the economic benefits, making a clear case for requiring this technology on all NYS wells, with few exceptions. RECs provide an immediate revenue stream by routing gas (methane and gas condensates) to a gas sales line that would otherwise be vented into the atmosphere or flared.. Alternatively, captured gas can be used for fuel, offsetting operating costs, or re-injected to improve well performance. Industry has demonstrated that RECs are both an environmental best practice and profitable.

In addition to being economically attractive for the operator, there are a number of other benefits of RECs:

- The collection of potentially explosive gas vapors, rather than venting them to the atmosphere. This improves well site safety, reduces worker exposure to harmful vapors, and limits overall corporate liability.
- The reduction in emissions, noises, odors, and citizen complaints associated with venting or flaring.
- The reduction in disposal costs, as a result of gas and condensate capture and sale.

[244] 2011 NYSDEC, RDSGEIS, Page 1-116.

- The elimination of the need to secure flare permits and provide flaring notifications.[245]
- The reduction of VOCs and HAPs. Unprocessed natural gas contains VOCs and HAPs, along with methane. Flaring, an alternative control device, can reduce VOCs and HAPs. However, flaring generates NO_X and particulate matter (PM), as well as other combustible byproducts. Many areas with significant oil and gas development have challenges achieving ozone and regional haze standards. Therefore, REC technology is a preferred alternative.
- Wells flow back to portable separation units for longer periods than would be allowed with direct venting into the atmosphere or flaring, providing improved well cleanup and enhanced well productivity.
- Fewer wells are drilled as more methane is kept in the system and sent to market, thereby reducing a range of environmental impacts.

While some operators report the voluntary use of RECs, many wells in the United States are still drilled without REC. And, even for companies that have announced the use of RECs, it is not clear how extensively RECs are implemented. Thus, many states have put REC requirements into effect.

The commercial availability of REC equipment has become so widespread that it is now required in several states. For instance, Colorado requires RECs on all oil and gas wells unless they are not technically and economically feasible.[246] Fort Worth, Texas requires RECs.[247] Wyoming has required RECs in the Jonah-Pinedale Anticline Development Area (JPAD) since 2007, and more recently, Wyoming has expanded this requirement to all Concentrated Development Areas (CDAs) of oil and gas in the state.[248]

In 2005, EPA estimated that an average of 7,000 Mcf of natural gas can be recovered during each REC.[249] In 2011, EPA increased the emission recovery estimate and created two distinct categories of wells that are major contributors to methane emissions: Unconventional Gas Wells (7,700 Mcf/well workover) and Low Pressure Gas Well Cleanup (1,400 Mcf/well/year). For each unconventional gas well completion, there is an opportunity to generate about $31,000 in gross revenue, creating a very short payout period if the operator invests in its own equipment.[250]

Investment in REC equipment is extremely profitable, with a conservative average investment cost of $10,000 per REC.[251] The payout occurs quickly if a contractor is hired and the operator only pays a per well REC equipment rental charge. As long as the gas that is captured and sold exceeds the equipment rental charge, the payout is immediate.

Oil and gas operators that have a sufficient number of wells to amortize the cost of REC equipment are finding it more economically attractive to invest in their own technology. Most of the companies that have gone this route report a one- to two-year payout, and substantial profitability thereafter, depending on the gas and condensate recovery rate.[252] For smaller operators, it is possible, and maybe more

[245] Flaring is not always practicable near populated areas or areas of high forest fire risk.

[246] Colorado Oil and Gas Conservation Commission, Rule § 805(b)(3)

[247] Fort Worth Texas, Ordinance No. 18449-02-2009.

[248] Wyoming Oil and Gas Production Facilities, Chapter 6, Section 2, Permitting Guidance, March 2010.

[249] United States Environmental Protection Agency, Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[250] (7,700 Mcf)($4/Mcf)= $30,800

[251] EPA's Green Completion PRO FACT Sheet No.703 estimates the cost between $1K and $10K; a $10K per completion cost estimate is conservative.

[252] EPA Natural Gas STAR, Green Completions, PRO Fact Sheet No. 703, September 2004.

financially feasible, to rent REC equipment from a contractor. The profitability math is simple. In 2005, the EPA estimated that, on average, 7,000 Mcf/well of natural gas could be captured, yielding a profit of $14K per well, with a payback of less than one year.[253] However, it is important to note that EPA's 2005 profitability calculations were based on lower gas prices ($3/Mcf) than the current market rate ($4+/Mcf). Using the EPA's new 2011 estimate of 7,700 Mcf/well and a gas price of $4/Mcf, each well, on average, has the potential to generate $31,000 in gross revenue. A portion of that revenue stream must be allocated to purchasing or renting the required REC equipment, but unless that cost is greater than $31,000 per well, a REC is a profitable endeavor. Profitability will vary based on the market price for gas and the cost of carrying out the REC.

The EPA has found that RECs are a major contributor to methane reductions on a national scale. In 2008, 50 percent of the EPA's Natural Gas STAR Program's annual total reductions for the oil and gas production sector was attributed to REC s.[254] Therefore, requiring this technology will be very important to NYS' and EPA's GHG emission reduction goals.

Recommendation No. 55: Drilling and well completion operations should be coordinated with gas line installation, enabling RECs for all wells drilled subsequent to the initial exploration well. Alternatively, methane gas should be used onsite to generate power, re-injected to improve well performance, or provided to local residents as an affordable fuel supply. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Wastewater Impoundments:

In 2009, HCLLC pointed out that centralized wastewater impoundments have the potential to be a major source of HAPs—EPA lists facilities that release 10 tons of a single HAP per year as major sources. The 2009 DSGEIS estimated 32.5 tons of methanol[255] per year—more than three times the HAP major source threshold—could be emitted from centralized wastewater impoundments.[256] This large amount of hazardous air pollution was identified as an unmitigated significant impact.

In 2009, HCLLC recommended the use of closed loop collection and tank systems, rather than wastewater impoundments, as a best practice. The 2011 RDSGEIS prohibits the use of wastewater impoundments at the drillsite, requiring closed loop collection and tank systems. This is a substantial improvement. However, the RDSGEIS does not prohibit centralized flowback impoundments at locations

[253] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[254] 2009 EPA Natural Gas STAR Program Accomplishments, available online at http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf. Total sector reductions (2008) = 89.3 Bcf of which 50 percent are the result of RECs (50% of 89.3 Bcf = 45 Bcf).

[255] EPA lists methanol as a hazardous air pollutant, but has not yet classified it with respect to carcinogenicity. The reproductive and developmental effect of methanol on humans is not yet understood. http://www.epa.gov/ttn/atw/hlthef/methanol.html. Testing in rats has yielded skeletal, cardiovascular, urinary system, and central nervous system malformations. American Conference of Governmental Industrial Hygienists (ACGIH), TLVs and BEIs, Threshold Limit Values for Chemical Substances and Physical Agents, Biological Exposure Indices, Cincinnati, OH, 1999. In humans, chronic inhalation or oral exposure may result in headaches, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, blurred vision, and blindness. Neurological damage, specifically permanent motor dysfunction, may also be a result. The Merck Index. An Encyclopedia of Chemicals, Drugs, and Biologicals. 11th ed. Ed. S. Budavari. Merck and Co. Inc., Rahway, NJ. 1989.

[256] 2009 NYSDEC, DSGEIS, Page 6-57.

away from the drillsite and fails to analyze the impacts of such centralization. This represents impermissible segmentation. It is recommended that centralized flowback impoundments be prohibited, however, if this recommendation is not adopted a new draft should be prepared analyzing the potential impacts posed by the reliance on centralized impoundments to store and treat HVHF wastewater and made available for public comment; such a significant analysis cannot be deferred until future site-specific review.

Despite the RDSGEIS's reliance on representations by industry that centralized flowback impoundments are not contemplated at this time, recent experience in Pennsylvania, and other states, reveals that industry's use of centralized flowback impoundments has become common practice. The RDSGEIS either needs to clearly prohibit the use of centralized flowback impoundments in NYS or analyze the potential environmental impacts, including human health impacts, posed by such use and develop ways to avoid or mitigate such impacts.

While industry may not presently intend to build centralized flowback impoundments in NYS, that could change in the future. Based on the use of centralized flowback impoundments as a common industry practice, this is a reasonably foreseeable impact, and unless prohibited is an unmitigated significant impact.

As proposed, there would be no limitations in place for these types of impoundments:

> *Since September 2009 industry has provided information that: (1) simultaneous drilling and completion operations at a single pad would not occur; (2) the maximum number of wells to be drilled at a pad in a year would be four in a 12-month period; and (3) centralized flowback impoundments, which are large volume, lined ponds that function as fluid collection points for multiple wells, are not contemplated [emphasis added].*[257]

Recommendation No. 56: The use of centralized impoundments to collect waste should be prohibited because these impoundments are a major source of air pollution. This prohibition should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

If centralized flowback impoundments are not prohibited, the potential adverse impacts to human health and the environment must be analyzed fully by NYSDEC. Given that the RDSGEIS includes no analysis whatsoever of the impacts of centralized flowback impoundments, a new draft must be prepared and made available for public comment in order to satisfy the requirements of SEQRA; deferring such analysis for later review would constitute impermissible segmentation. Moreover, mitigation measures to address the potential significant impacts must be included in the SGEIS and codified in the NYCRR.

Gas Dehydrators:

In 2009, HCLLC pointed out that gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions.

[257] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15-16, and Page 6-111.

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. These gases are vented to atmosphere unless pollution controls are installed. Best technology for dehydration units includes the installation of flash-tank separators to recover gas pollutants. Alternatively, pollutants can be routed to a vapor collection/destruction unit, or desiccant dehydrators can be used. Desiccant dehydrators have shown to cost less than flash-tank separators, have lower operating and maintenance costs, and control 99% of HAPs.[258]

The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement.

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, requires:

> *The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control device to limit the benzene emissions to one ton/year;*[259]

The 2011 RDSGEIS also requires a GHG impacts mitigation plan[260] that includes an evaluation of EPA Natural Gas STAR Best Practices for methane and other GHG emissions. However, it does not make GHG emission controls for gas dehydrators mandatory.

NYSDEC's requirement to control emissions from all dehydrators emitting more than one ton per year of benzene will result in emission control on a number of NYS dehydration units. However, smaller dehydration units that do not fall under this requirement may still have economical methane emission control opportunities.

In 2011, the EPA estimated that approximately 8 Bcf of methane is emitted from gas dehydration systems annually. Most of this methane is emitted from smaller glycol dehydration units currently fall below federal regulatory thresholds for emission control. That methane could instead be captured for sale or use as fuel.[261] While the EPA requires a number of large glycol dehydrators to install emission controls, under the federal Maximum Achievable Control Technology (MACT) standards at 40 CFR Part 63, Subpart HH, small glycol dehydrators are typically exempt. Many small operating glycol dehydrator units do not have flash tank separators, condensers, electric pumps, or vapor recovery installed.

There are four straightforward solutions readily available to control methane emissions from TEG dehydrator units, including: installing a flash tank separator; optimizing the glycol circulation rate; rerouting the skimmer gas; and installing an electric pump to replace the natural gas driven energy exchange pump.

A typical glycol dehydration system includes the following components:

- Glycol Contactor: Wet gas enters the glycol contactor. Glycol removes moisture from the gas by the process of physical absorption. Along with removing moisture, the glycol also absorbs methane,

[258] Fernandez, R., Petrusak, R., Robinson, D., Zavadil, D., Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[259] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109, and Appendix 10, Attachment A.

[260] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[261] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

VOCs, and HAPs. Dry gas exits the glycol contactor absorption column and is either routed to a pipeline or a gas plant.

The glycol contactor unit plays the primary role in dehydrating gas to pipeline specifications; the rest of the glycol dehydration system is required to convert the now moisture rich glycol back into a lean product that can be re-used to dehydrate more incoming gas. Therefore, the next step in the process is to route the moisture rich glycol to "regenerator" and "reboiler" units.

- Glycol Regenerator & Reboiler: Glycol loaded with moisture, methane, VOCs, and HAPs ("rich glycol") exits the bottom of the glycol contactor unit and is routed to the glycol regenerator and reboiler units, where the absorbed components are removed and "lean" glycol is created. If emission controls are not installed, methane, VOCs, HAPs, and water are boiled off and vented to atmosphere from the regenerator and reboiler units.

  One way to limit the amount of methane, VOCs, and HAPs emitted to the atmosphere from the regenerator and reboiler units is to install a flash tank separator.

- Flash Tank Separator: The installation of a flash tank separator between the glycol contactor and the glycol regenerator/reboiler units creates a pressure drop in the system, allowing methane and some VOCs and HAPs to flash out of (separate from) the glycol. The amount of pressure drop that can be created is a function of the fuel gas system pressure or compressor suction pressure, because methane gas flashed-off at the flash tank separator is then sent to be used as fuel in the TEG reboiler or compressor engine. Simply put, the pressure can only be dropped to a pressure that still exceeds the fuel gas pressure, allowing the collected methane gas to flow into the fuel system. Flash tank separators typically recover 90 percent of the total methane and approximately 10 to 40 percent of the total VOCs that would otherwise be vented to atmosphere. Methane emissions can also be controlled by taking the simple step of adjusting the rate that glycol is circulated in the system.

  In 2005, the EPA estimated that the installation of a flash tank separator, on average, resulted in 10 Mcfd (3,650 Mcf/yr) of methane gas captured for sale or use as fuel for each TEG dehydrator (typically a 90 percent reduction in methane emissions). And in 2009, the EPA reported that flash tank separators are installed on *only*: 15 percent of the dehydration units processing less than 1 MMcfd; 40 percent of units processing 1 to 5 MMcfd; and between 65 and 70 percent of units processing more than 5 MMcfd.[262] Therefore, an emission control target still exists, especially for small dehydration units.

  The installation of a flash tank separator also improves the efficiency of downstream components (e.g. condensers) and reduces fuel costs by providing a fuel source to the TEG reboiler or compressor engine.[263]

- Glycol Recirculation Pump: Methane emissions are directly proportional to the glycol circulation rate. Circulating glycol at a rate that exceeds the operational need for removing water content from gas unnecessarily increases methane emissions. Glycol circulation rates are typically set at the maximum to account for peak throughput. Gas pressure and flow rate decline over time, requiring the glycol circulation rate to be adjusted to meet operational need. Optimizing the glycol circulation merely requires an engineering assessment and a field operating adjustment. If the glycol dehydration unit includes a condenser, methane emissions can be collected and used for fuel or destroyed, rather than being vented to atmosphere.

  In 2005, the EPA estimated that optimizing the glycol circulation rate could result in a wide range of methane capture from 1 to 100Mcfd (18,250 Mcf/yr using a median estimate of 50 Mcfd). [264]

[262] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

[263] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

- Condensers: Some glycol reboilers have condensers to recover natural gas liquids and reduce VOCs and HAPs. However, condensers do not capture methane (because it is a non-condensable gas); therefore, the addition of a condenser does not reduce methane emissions. When condensers are installed, methane gas is typically vented to atmosphere. Alternatively, this methane gas (called "skimmer gas") can be routed to the reboiler firebox or other low-pressure fuel gas systems.[265] In 2005, the EPA estimated that rerouting glycol skimmer gas could result in an average methane capture of 21 Mcfd (7,665 Mcf/yr). [266]
- Electric Pump vs. Energy-Exchange Pumps: Historically, gas-assisted glycol pumps have been used. Where there is an electric supply, the gas-assisted glycol pumps can be replaced with an electric pump. Gas-assisted pumps are driven by the expansion of the high-pressure gas entrained in the rich glycol that leaves the contactor, supplemented by the addition of untreated high-pressure wet (methane rich) natural gas. The high-pressure gas drives pneumatic pumps. Much like pneumatically operated valves, pneumatically operated pumps vent methane.

  In 2007, the EPA estimated that between 360 and 36,000 Mcf/yr in methane emission reductions could be achieved by installing an electric pump to replace the natural gas driven glycol energy exchange pump; the wide range in methane emission reductions is a function of the large variation in equipment sizes.[267]

In 2007, EPA estimated the total potential emission reductions at any given glycol dehydration unit is a function of how many emission control solutions are installed. The total may range from 3,700-35,000 Mcf/year ($14.8K-$140K worth of gas leakage). In 2011, EPA estimated 38,000 Mcf/year ($152K).[268] Therefore, controlling methane emissions and other GHG emissions from dehydration units is good business.

However, despite the clear environmental and financial benefits, not all members of the oil and gas industry voluntarily invest in methane control options. Therefore, it is recommended that NYSDEC require operators to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made.

> Recommendation No. 57: Natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

[264] The wide range in methane capture opportunity is a function of the dehydrator size, and how efficiently the operator previously optimized the glycol circulation rate.

[265] USEPA Natural Gas STAR, Reroute Glycol Skimmer Gas, PRO Fact Sheet No. 201, 2004.

[266] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[267] EPA Natural Gas STAR, Natural Gas Dehydration, Producers Technology Transfer Workshop, Durango Colorado, September 13, 2007.

[268] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

Diesel Engine Emission Control:

In 2009 AKRF recommended that diesel engines should be Tier 2 or higher. AKRF pointed out that "Tier 0" engines could be used, unless NYSDEC limited engines by certification type. Uncertified engines have extremely high emission rates for criteria pollutants such as particulate matter.

Additionally, AKRF recommended that diesel particle filters be installed on diesel engines to reduce particulate matter that has shown to aggravate respiratory systems and is known to be carcinogenic. More specifically AKRF recommended that all engines with a power output of 50 horsepower or greater be equipped with a diesel particle filter, either by the original engine manufacturer or by retrofit.

The 2011 RDSGEIS, Appendix 10 Proposed Supplementary Permit Conditions for HVHF, addressed most of AKRF's recommendations, by prohibiting Tier 0 engines, requiring Tier 2 engines in most cases, and requiring both Tier 1 and Tier 2 engines to install emission controls. NYSDEC proposes that:

- *No uncertified (i.e., EPA Tier 0) drilling or hydraulic fracturing engines will be used for any activity at the well sites;*
- *The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both particulate traps (CRDPF [Continuously Regenerating Diesel Particulate Filters]) and SCR [Selective Catalytic Reduction] controls. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence; and*
- *The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence [emphasis added].*[269]

NYSDEC estimates that 25% of the engines may be Tier 1 engines, and to ensure compliance with National Ambient Air Quality Standards (NAAQS) it requires the engine to be equipped with both CRDPFs and Selective Catalytic Reduction controls.

While NYSDEC has proposed a number of improvements for diesel engine emission control, the RDSGEIS did not assess whether Tier 1 engines could be eliminated altogether.

> Recommendation No. 58: The SGEIS should examine whether it is possible to eliminate Tier 1 engine use. Further examination of AKRF's recommendation to prohibit Tier 1 engine use is warranted.

[269] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109 and Appendix 10, Attachment A, Condition 9-11.

Leak Detection & Repair Program:

In 2009 HCLLC recommended that NYSDEC require Leak Detection and Repair (LDAR) programs including acoustic detectors and infrared technology to detect odorless and colorless leaks. Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs.

Methane gas leaks can occur from numerous locations at gas facilities—valves, drains, pumps, threaded and flanged connections, pressure relief devices, open-ended valves and lines, and sample points—as gas moves through equipment under pressure. These leaks are called "fugitive emissions."

Fugitive emissions from equipment leaks are unintentional losses of methane gas that may occur due to normal wear and tear, improper or incomplete assembly of components, inadequate material specifications, manufacturing defects, damage during installation or use, corrosion, or fouling.[270]

Because methane is a colorless, odorless gas, leaks often go unnoticed. Historically, leak checks were only performed on equipment components when they were first installed, using a soap bubble test or hand held sensor, to ensure the installation was leak tight. After installation leaks were not typically monitored or repaired unless they became a significant safety hazard. For example, a significant gas leak would be repaired if area, building, or employee monitors set off alarms or if olfactory, audible, or visual indicators observed by facility employees identified the leak. Under these circumstances, the leaks had usually become an obvious safety concern. As a result, methane leaks at outdoor facilities and unmanned facilities often went undetected for long periods of time.

Fugitive emission control is a two-part process that includes: (1) a monitoring program to identify leaks and (2) a repair program to fix the leak. Monitoring program type and frequency is a function of the type of component, and how the component is put to use. In most cases, monitoring programs can be intermittently scheduled at a certain frequency (e.g. monthly or quarterly) to identify leaking equipment. However, permanent leak sensors may be required to detect chronic leakers.[271]

There are many different monitoring tools that can be used to identify leaks, including electronic gas detectors, acoustic detectors, ultrasound detectors, flame ionization detectors, calibrated bagging, high volume sampler, end-of-pipe flow measurement, and infrared leak detection. Once leaks are identified, the operator can evaluate what is causing the leak and develop a replacement or repair program to mitigate the leak.

For example, a hand held infrared camera can be used as a screening tool to detect emissions that are not visible to the naked eye. An infrared camera produces images of gas leaks in real-time. [272] It is capable of identifying methane leaks, but cannot quantify the amount of the leak. Infrared cameras produce photos that show methane gas leaks.

Once a leak is identified, and a more quantitative leak flow rate determination is needed, other measurement devices such as Hi-Flow Samplers, Vent-Bag Methods, and Anemometers may be used.[273] Hi-Flow Samplers capture the entire leak, measuring the leak rate directly for leaks up to 10 cubic feet per

[270] USEPA, Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry, 2009.

[271] Squarek, J. (Canadian Association of Petroleum Producers), Layer, M. (Environment Canada) and Picard, D. (Clearstone Engineering Ltd.), Development of a Best Management Practice in Canada for Controlling Fugitive Emissions at Upstream Oil and Gas Facilities, 2005.

[272] Snider, P., Advanced Well Completion Technology to Reduce Methane Emissions and Use of Infared Cameras for Leak Detection, Global Forum on Flaring and Venting Reduction and Natural Gas Utilisation, 2008.

[273] Heath, M.W., Leak Detection and Quantification of Fugitive Methane Emissions at Natural Gas Facilities, 2009.

minute (cfm), providing leak flow rate and concentration data.[274] Toxic Vapor Analyzers and acoustic leak detection systems are other methods to identify methane leaks.[275]

Fugitive emissions management is an ongoing commitment, not a one-time initiative. The potential for fugitive equipment leaks will increase as facilities age. Successful fugitive emission control plans require trained personnel, emissions testing equipment, and performance tracking systems.

In 2009, the EPA examined the profitability of repairing equipment leaks at oil and gas facilities and found that leak repair is not only an important air pollution control and safety measure, but also is a profitable investment.[276] EPA reports that fugitive emissions control provides numerous benefits including: reduced maintenance costs and downtime, improved process efficiency, a safer work environment, a cleaner environment, and resource conservation.

The 2011 RDSGEIS acknowledges the potential impact of gas leaks, and requires a Leak Detection and Repair Program to be included in the operator's GHG Mitigation Plan.

> *Because the production phase is the greatest contributor of GHGs and in an effort to mitigate VOC and methane leaks during this phase, the Department proposes to require, via permit condition and/or regulation, a Leak Detection and Repair Program would* ***include as part of the operator's greenhouse gas emissions impacts mitigation plan*** *which is required for any well subject to permit issuance under the SGEIS [emphasis added].*[277]

The 2011 RDSGEIS specifies the minimum requirements for a Leak Detection and Repair Program.

> *The Leak Detection and Repair Program within the greenhouse gas emissions impacts mitigation plan would contain the following minimum requirements.*
>
> - *There would be an ongoing site inspection for readily detected leaks by sight and sound whenever company personnel or other personnel under the direction of the company are on site. Anytime a leak is detected by sight or sound, an attempt at repair should be made. If the leak is associated with mandated worker safety concerns, it should be so noted in follow-up reports;*
> - *Within 30 days of a well being placed into production and at least annually thereafter, all wellhead and production equipment, surface lines and metering devices at each well and/or well pad including and from the wellhead leading up to the onsite separator's outlet would be inspected for VOC, methane and other gaseous or liquid leaks. Leak detection would be conducted by visible and audible inspection and through the use of at least one of the following: 1) electronic instrument such as a forward looking infrared camera, 2) toxic vapor analyzer, 3) organic vapor analyzer, or 4) other instrument approved by the department;*
> - *All components noted above that are possible sources of leaks would be included in the inspection and repair program. These components include but are not limited to: line heaters, separators, dehydrators, meters, instruments, pressure relief valves,*

[274] http://www.heathus.com/_hc/index.cfm/about-us/vision

[275] Methane to Markets, Reducing Methane Emissions through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[276] Methane to Markets, Reducing Methane Emissions Through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[277] 2011 NYSDEC, RDSGEIS, Page 7-114 .

vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the onsite separator's outlet;

- *For each detected leak, if practical and safe an initial attempt at repair would be made at the time of the inspection, however, any leak that is not able to be repaired during the inspection may be repaired at any time up to 15 days from the date of detection provided it does not pose a threat to on-site personnel or public safety. All leaking components which cannot be repaired at detection would be identified for such repair by tagging. All repaired components would be re-inspected within 15 days from the date of the initial repair and/or re-repair to confirm, using one of the approved leak detection instruments, the adequacy of the repair and to check for leaks. The department may extend the period allowed for the repair(s) based on site-specific circumstances or it may require early well or well pad shutdown to make the repair(s) or other appropriate action based on the number and severity of tagged leaks awaiting repair; and*
- *Site inspection records would be maintained for a minimum period of 5 years. These records would include the date and location of the inspection, identification of each leaking component, the date of the initial attempt at repair, the date(s) and result(s) of any re-inspection and the date of the successful repair if different from initial attempt [emphasis added].*[278]

The RDSGEIS proposal to require an LDAR Program is a substantial improvement; however, a few changes to the proposed program are recommended:

- An LDAR inspection should be conducted at well/drillsite start-up, not 30 days after. It is best practice to construct and install equipment and test for leaks prior to operation. Equipment should not be operated for 30 days without completing this minimum standard of care.
- Quarterly testing with an infrared camera (as a screening method) should be required, instead of annual testing, as a minimum standard. If the infrared camera screening indicates a leak, the leak location, if clearly pin pointed, should be repaired. Or additional testing should be conducted using more sophisticated tools (described above) to pin-point the leak location, followed by a repair.
- Testing should include all equipment located on the drillsite. As proposed, the RSGEIS suggests the LDAR Program end at the separator's outlet. Equipment will be located downstream of the separator outlet, and prior to the connection the gas transit line that could potentially leak gas. Therefore, it is recommended that the LDAR Program be implemented for all equipment on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet.

Recommendation No. 59: The proposed LDAR Program should be revised to require: a drillsite LDAR inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the NYCRR, and be required for all natural gas operations, not just HVHF operations.

[278] 2011 NYSDEC, RDSGEIS, Page 7-115 and 7-116.

Cleaner Power and Fuel Supply Options:

In 2009, HCLLC and AKRF recommended that the SGEIS evaluate the use of cleaner engines and fuels.

In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, thus eliminating local diesel exhaust. This alternative would be particularly beneficial where operations are planned near sensitive receptors and in areas that already suffer from high air pollutant loading. Electric engines have the added benefit of quieter operation and less noise impact in urban and suburban settings.

In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel. Natural gas fired engines produce less air pollution that diesel engines. A natural gas supply should be available for all wells drilled on a multi-well drillsite, except the first well. Once the first well is drilled using diesel, subsequent wells can be drilled using the natural gas produced by that well to generate power. Smaller temporary gas processing units are available to process wellhead gas to the quality required for equipment use. The use of dual fuel engines would enable switching from diesel to natural gas once it is available.

The use of electric and natural gas engines would result in reduced local pollutant emissions and overall GHG emissions (both grid power and natural gas have a lower carbon footprint than diesel) and generally would have associated cost savings given the reduced fuel transportation and storage needs (e.g. double-wall tanks) and the reduced risk of tank leakage and cleanup associated with the use of fuel gas produced on-site or electric power.

The 2011 RDSGEIS: The 2011 RDSGEIS did not examine cleaner power and fuel supply options. The RDSGEIS only briefly mentioned that electric engines and cleaner fuel options were recommended[279] but disregarded the recommendations as "unlikely to be practically implemented to any extent" due to the remote nature of the drillsites. This analysis is incomplete and fails to consider viable alternatives for mitigating air pollution.

Foremost, electric power is available in all suburban and urban areas of NYS, and is currently located in many rural areas as well to supply power to homes, farms and businesses.

Secondly, the use of natural gas-fired engines on a multi-well drillsite is a commonly used mitigation measure. While diesel engines are often used as the prime mover of power supply for rotary well drilling, natural gas or dual fuel (diesel/gas) engines are available to take advantage of cleaner fuel supplies.[280] EnCana, a gas producer, reports that natural gas-fired rigs reduce air pollution by 90% compared to diesel fired rigs.[281] Power can also be supplied to the drilling rig by a natural gas-powered reciprocating turbine that can generate electricity on site.

[279] 2011 NYSDEC, RDSGEIS, Page 6-144.

[280] www.naturalgas.org.

[281] EnCana 2005 Annual Report.

Recommendation No. 60: In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

18. Surface Setbacks from Sensitive Receptors

Background: The 2009 DSGEIS did not propose sufficient safety or quality-of-life surface setbacks from sensitive human and environment resource receptors. This problem persists in the 2011 RDSGEIS. Noise, traffic, odor, air, and water pollution impacts to sensitive receptors will be significant if the small setbacks proposed in the RDSGEIS are adopted.

Surface setbacks should be increased to mitigate significant impacts and to create a safe environment for the affected public. For example:

- Blowouts can eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. These pollutants can then be further transported in the subsurface or on the surface, creating a large area of contamination in a very short amount of time.
- Chemicals, fuels, and explosive charges (e.g. perforating guns) may be located at the drillsite and may pose hazards to the public, in addition to the flammable, explosive, and hazardous gases (e.g. hydrogen sulfide gas, benzene) that are produced from the well and associated equipment.
- The potential radius of impact for explosions, fire, and other industrial hazards should be considered. For example, the city of Forth Worth, Texas uses the International Fire Code as the basis for its minimum 600' setback from Barnett shale gas drilling operations.[282] Whereas, NYCRR only provides for a 100' setback from a home. 6 NYCRR § 553.2.
- High pressure hose leaks can spray industrial fluids off the drilling pad and onto surrounding properties or waters. The radius of contamination will depend on system pressure, shut-down reaction timing, wind speed, and other factors.

For example, in September 2009, 1,300 gallons of well chemicals were leaked during a hydraulic fracture treatment at the Cabot Heitsman 4H well located in Susquehanna Country, Pennsylvania, and flowed into the nearby Steven's Creek located more than 100 feet away, despite protections in place under the operator's required Pennsylvania PPC plan.[283]

Recommendation No. 61: The SGEIS should provide scientific and technical justification for each setback distance proposed to demonstrate how that distance is protective of the nearby sensitive receptor. A hazard identification analysis should be completed to assess the safe distance from human and sensitive environmental receptors to proposed shale gas drilling and HVHF operations. The analysis should assess blowout radius, spill trajectory, explosion hazards, other industrial hazards, fire code compliance, human health, agricultural health, and quality-of-life factors. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

While statewide minimum setbacks to protect human health, provide safe buffers, and protect the environment should be established, both the RDSGEIS and NYCRR should include a provision to allow local communities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics.

[282] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009.

[283] Cabot Oil & Gas Corporation, Engineering Study, for submittal to PADEP, In Response to Order dated September 24, 2009, prepared by URS Corporation for Cabot, October 9, 2009.

Recommendation No. 62: The SGEIS and NYCRR should allow local zoning authorities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics. The ability to improve local setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2011 RDSGEIS: The 2011 RDSGEIS proposes additional setbacks from aquifers, wells, and water bodies for HVHF operations, but does not establish additional setbacks from homes or public buildings.

NYSDEC does not provide scientific or technical justification in the RDSGEIS for the setback distances it has selected. Setbacks ranging from 150' to 2,000' are included in the RDSGEIS without justification for how or why those particular distances were selected or determined to be adequate to protect water resources.

The 2011 RDSGEIS proposes the following setbacks:

- **500' setback from primary and principal aquifers**. However, for principal aquifers, drilling and HVHF operations can occur within that 500' buffer with additional review, and for both primary and principal aquifers the setback distance will be reconsidered in two years in a yet to be determined process.

  > *Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing).*[284]
  >
  > *For at least two years from issuance of the first permit for high-volume hydraulic fracturing, proposals for high-volume hydraulic fracturing at any well pad within 500 feet of principal aquifers, would require (1) site-specific SEQRA determinations of significance and (2) individual State Pollutant Discharge Elimination System (SPDES) permits for stormwater discharges. The Department would re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of the 500-foot boundary.*[285]

- **2,000' setback from a public water supply**, unless a shale gas well is located within 1000' of a subsurface water supply designated by the New York City Department of Environmental Protection (NYCDEP). However, these setbacks will be reconsidered in three years in a yet to be determined process.

  > *The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing).*[286]
  >
  > *The Department proposes that site-specific environmental assessments and SEQRA determinations of significance be required for … any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure.*[287]

[284] 2011 NYSDEC, RDSGEIS, Page 1-17.
[285] 2011 NYSDEC, RDSGEIS, Page 1-18.
[286] 2011 NYSDEC, RDSGEIS, Page 3-15.
[286] 2011 NYSDEC, RDSGEIS, Page 3-16.
[287] 2011 NYSDEC, RDSGEIS, Page 3-15.

Recommendation No. 63: The process for revising the 500' setback from primary and principal aquifers and the 2,000' setback from a public water supply in two and three years, respectfully, is unclear. NYSDEC should clarify the review process, including an explanation of its plans for public review and comment. NYSDEC should revise its regulations at 6 NYCRR § 617.4(b) to provide that the siting of any oil or gas well within 500' of a primary aquifer or within 2,000 of a public water supply is a Type I action.

- **500' setback from a private water well**.

> *The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 500 feet of private drinking water wells or domestic uses springs, unless waived by the owner.*[288]

The RDSGEIS provides no rationale as to why a public water supply would be afforded a 2,000' setback, while a private water well would only be afforded at 500' setback.

Recommendation No. 64: The SGEIS should examine whether waivers to the 500' private water well setback comport with federal law and the requirement to protect Underground Sources of Drinking Water (USDWs). The SGEIS should provide technical justification for any reduction in this setback, and should not allow a private well owner to reduce the setback such that it poses a risk to its water supply, as well as other user in the area. Private land owners should not be allowed to waive setbacks from private water wells and adversely affect the water quality of neighboring wells.

- **150' setback from a stream, storm drain, lake, or pond**.

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.*[289]

The 150' setback language conflicts with the 2,000' setback language above, because it allows a closer setback from lakes, rivers and streams than from a public water supply. It is not clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback.

On October 3, 2011 Pennsylvania Governor Corbett announced plans to implement the Marcellus Shale Advisory Commission recommendation to increase the setback distance for wells near streams, rivers, ponds and other bodies of water to at least 300'.[290] An increased set back to at least 300' should also be considered by NYS.

[288] 2011 NYSDEC, RDSGEIS, Page 7-76.

[289] 2011 NYSDEC, RDSGEIS, Page 7-76.

[290] Pennsylvania Office of the Governor, News Release, Governor Corbett Announces Plans to Implement Key Recommendations of Marcellus Shale Advisory Commission, October 3, 2011.

Recommendation No. 65: The conflicting language between the 150' setback requirement and 2,000' setback requirement for lakes, rivers, and streams needs to be resolved in both the SGEIS and the NYCRR. As drafted, neither the RDSGEIS nor the NYCRR are clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback. NYSDEC should indicate whether it intends to apply the 150' setback only to surface water resources that are not actual or potential public drinking water supplies. NYSDEC should also explain whether the 150' set back is sufficient to protect those water resources, or whether this setback should be increased. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

- **4,000' setback from NYC and Syracuse watersheds**.

Accordingly, the Department recommends that regulations be adopted to prohibit high-volume hydraulic fracturing in both the NYC and Skaneateles Lake watersheds, as well as in a 4,000 -foot buffer area surrounding these watersheds, to provide an adequate margin of safety from the full range of operations related to high-volume hydraulic fracturing that extend away from the well pad. The Department also is presenting this proposal based on its consistency with the principles of source water protection and the "multi-barrier" approach to systematically assuring drinking water quality.[291]

Recommendation No. 66: The 4,000' setback from NYC and Syracuse watersheds should be added to the proposed regulatory revisions for operations associated with HVHF at 6 NYCRR § 560.4. The SGEIS and NYCRR should also clarify if activities associated with HVHF drilling and completions will be prohibited underneath the watershed as well as on the surface.

NYSDEC has not provided engineering or scientific justification for the setback distances it has selected, other than a brief assessment of the setbacks that are allowed in other states. NYSDEC ultimately selected setbacks that are not as protective as those identified by the agency's consultants. For example, the RDSGEIS, states:

> *The required setbacks from surface water supplies in other states reviewed by Alpha vary between 100 and 350 feet.*[292]

NYSDEC's consultants collected information that shows a more protective 350' setback is in use in other states; however, NYSDEC concludes that only a 150' setback will be required. This is less than half the distance of the most protective standard found by NYSDEC's consultants, and the 150' setback can be further reduced at NYSDEC's discretion based on a site-specific SEQRA review:

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.* [293]

[291] 2011 NYSDEC, RDSGEIS, Page 7-56.

[292] 2011 NYSDEC, RDSGEIS, Page 7-76.

[293] 2011 NYSDEC, RDSGEIS, Page 7-76.

Of note, the RDSGEIS does not address setbacks from homes or public buildings. The RDSGEIS merely requires the operator to document the distance from the proposed drilling and HVHF operations to "…any residences, occupied structures or places of assembly within 1,320 feet."[294] However, no new setback is established for homes or public buildings, other than required by current regulations.

NYCRR Proposed Revisions: The new setbacks proposed in the RDSGEIS are codified in regulation at 6 NYCRR §560.4. These setbacks would apply only to wells that undergo HVHF. NYSDEC does not explain why these setbacks would not apply to all oil and gas well drilling in NYS, despite the fact that 6 NYCRR § 553.2 (Well Surface Restrictions) applies to all NYS oil and gas wells. NYSDEC has not justified its limiting of new setback increases to HVHF wells only.

Recommendation No. 67: The setback increases proposed in the RDSGEIS should apply to all oil and gas drilling in NYS and should be codified at 6 NYCRR § 553.2.

The existing NYCRR allows drilling, HVHF operations, and production equipment to be located within 100' from an inhabited private dwelling and within 150' from a public building or area that may be used as a place of "resort, assembly, education, entertainment, lodging, trade, manufacture, repair, storage, traffic or occupancy by the public." The existing NYCRR also allows drilling, HVHF operations, and production equipment to be located within 50' from a public stream, river, or other body of water. There is no required setback from buildings or structures used for agriculture. 6 NYCRR § 553.2.

The proposed revisions to the NYCRR include 500' setbacks from primary aquifers, 2,000' setbacks from public water supplies, and 500' setbacks from private wells. Proposed 6 NYCRR § 560.4. However, these setbacks apply only to wells that undergo HVHF, and do not apply to all wells that undergo hydraulic fracturing operations in NYS.

NYSDEC's setback analysis does not take into account that directional drilling technology enables wells to be drilled to a bottom-hole location at 3-5 miles[295] away from a wellhead. In directional drilling, it is now common for the horizontal displacement of the bottom hole location to be several times the total vertical depth (TVD) of the well. For example, a well with a vertical depth of 5,000' could have a bottom hole horizontal displacement of 10,000-15,000' from the drill site, or more. A well with a vertical depth of 7,000' could have a bottom hole horizontal displacement of 14,000-21,000' from the drill site, or more. For example, in 1997, BP drilled a well to approximately 5,300' achieving a 33,182' horizontal displacement, meaning the wellhead was located over 6 miles away from the hydrocarbon target.[296] In 1997, a 6-mile horizontal displacement was a great feat; now, extended reach drilling (ERD) is commonplace in the industry, and wells are routinely drilled to hydrocarbon targets miles away from the wellhead.

Given the flexibility afforded by the fact that 640-acre spacing units may vary in shape, from square to rectangular, and that surface drillsites need not be located over the spacing unit, well operators utilizing directional drilling technology have a greater ability to select surface drillsite locations that optimize distance from sensitive public and private resources.

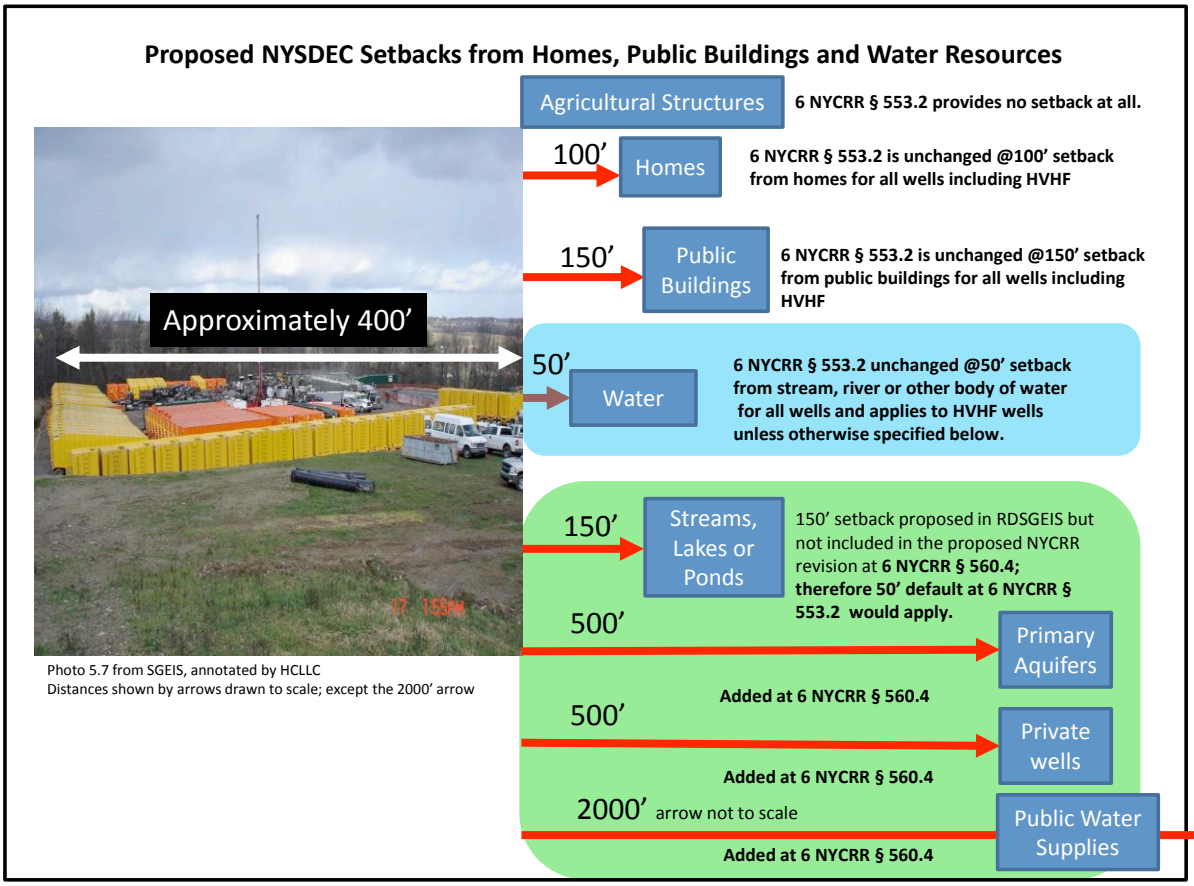
As shown in the figure below, the setbacks currently proposed in the RDSGEIS and in the NYCRR are inadequate. Shale drilling and HVHF operations within 100'-150' of homes and public buildings pose a direct safety risk, not to mention the health and quality of life impacts presented. NYSDEC is proposing

[294] 2011 NYSDEC, RDSGEIS, Page 3-10.

[295] Well step-out distance that can be achieved will depend on well depth.

[296] BP, Extended-Reach Drilling: Breaking the 10-km Barrier, 1997.

to allow shale drilling and HVHF operations to run 24 hours a day, 7 days a week, which will result in significant impacts to human health and quality of life—disrupting sleep, work, schooling, and recreational patterns for nearby residents.



By comparison, the local zoning setback requirements for Barnett Shale development implemented in the urban area of Fort Worth, Texas are substantially larger than those proposed for NYS.[297] As shown in the figure below, the required setback from a home is six times larger at 600', as compared to NYS' 100' setback. Additionally, Fort Worth, Texas has implemented setbacks of at least 300' from public buildings and 600' from schools, which is more than double what is proposed by NYSDEC.[298]

At a state level, Wyoming requires a minimum setback of 350' from "water supplies, residences, schools, hospitals, and other structures where people are known to congregate."[299] The below photograph shows the proximity of homes to a well pad in Pennsylvania, where a 200' minimum setback from homes is required.[300]

[297] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009; the Code of Ordinances of the City of Forth Worth § 15-36(A).

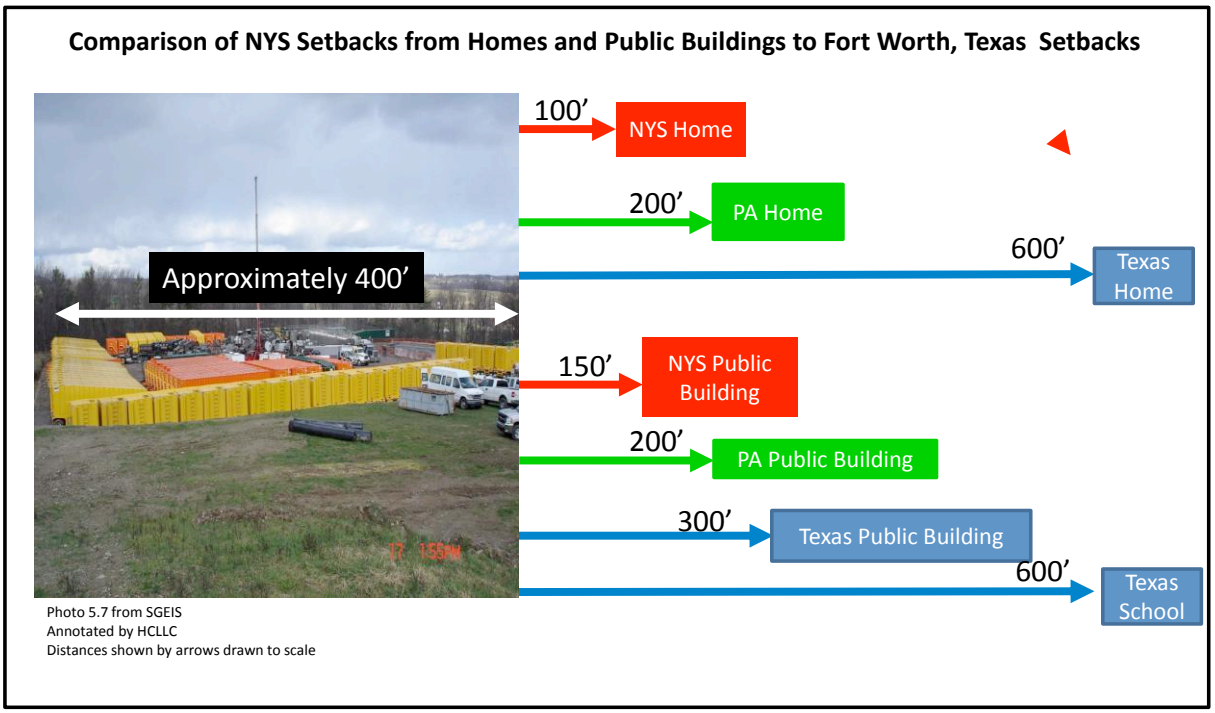
[298] The Code of Ordinances of the City of Forth Worth § 15-34(N)(7), § 15-36(A).

[299] Wyo. Admin. Code OIL GEN Ch. 3 § 22(b).

[300] Governor's Marcellus Shale Advisory Commission Report, Prepared for Governor Corbett of Pennsylvania, July 22, 2011.



The photo above shows homes within close proximity to shale drilling operations in Hopewell Township, Washington County, PA.



Recommendation No. 68: Improved setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Specifically, the SGEIS and NYCRR should be revised at 6 NYCRR § 553.2 to include the following minimum setbacks: homes, public buildings, and schools (1,320'; ¼ mile); private and public wells, primary aquifers, and other sensitive water resources (4,000'); and other water resources (660'; 1/8 mile). Additionally, NYSDEC should clarify the authority of local zoning authorities to establish minimum setbacks that are more protective than NYS' minimum standards in order for localities to address unique and site-specific local concerns and community characteristics.

In addition to the inadequate minimum setback requirements, the NYCRR allows an operator to move its surface location by 75' without obtaining a permit amendment. 6 NYCRR § 552.3(b). Absent NYSDEC and public review, a 75' adjustment is very significant, especially when setbacks as low as 50' to 150' are used. The regulations at 6 NYCRR § 552.3 explain that a 75' surface location adjustment is allowed, without any permit amendment process, to account for surface obstructions or topography. However, if an operator's due diligence and site planning during the original permit process include an examination of surface obstructions and topography, later adjustments should not be necessary.

Recommendation No. 69: The NYCRR should be revised at 6 NYCRR § 552.3 to allow the well location to be adjusted by 75' without a permit amendment only if all the statewide and local setback requirements are still preserved.

The proposed regulations that govern HVHF SPDES permits also suffer from inadequate minimum setback requirements. The revisions proposed to 6 NYCRR § 750-3.3 include: a 4,000' setback from an unfiltered water supply; a 500' setback from a primary aquifer; no operations within a 100-year floodplain; and a 2,000' setback from a public water supply, including wells, natural lakes, man-made impoundments, rivers and streams. However, neither the existing regulations nor the proposed revisions to 6 NYCRR § 750-3.3 include setbacks from streams, rivers, or other bodies of water that are not specifically designated as public water supplies. Thus, HVHF operations potentially could be as close as 50' to streams, rivers, or other bodies of water, based on 6 NYCRR § 553.2. Also, the proposed regulations do not require a minimum setback of HVHF operations from private wells.

Further inconsistency is introduced in the proposed revisions to 6 NYCRR § 750-3.21, which prohibit HVHF operations within 100' of a wetland. While this setback requirement is recognized in the RDSGEIS,[301] the proposed revisions to 6 NYCRR § 553.2 and 6 NYCRR § 560.4 do not include a parallel requirement. These sections of the regulations should be revised to include a wetland setback.

Recommendation No. 70: The NYCRR should be revised at 6 NYCRR § 553.2 to include a wetland setback of at least 100' as described in the RDSGEIS.

The proposed revisions to 6 NYCRR § 750-3.21(f)(3) do not authorize the issuance of a SPDES permit for HVHF operations within 150' of storm drains, lakes, ponds, and perennial or intermittent streams, which conflicts with the 50' setback established at 6 NYCRR § 553.2. There remains confusion about which setbacks would be applied to lakes, ponds, and perennial or intermittent streams and rivers.

Recommendation No. 71: The NYCRR should be revised at 6 NYCRR § 750-3.3, 6 NYCRR § 750-3.2, 6 NYCRR § 553.2, and 6 NYCRR § 560.4 to provide consistent setback requirements that are protective of water sources, including rivers, streams, lakes, and private water supplies.

NYCRR should be clear that the intent, as stated in the RDSGEIS, is to measure setbacks from the edge of the drillsite, and to attempt to center wells on the drillsite to maximize the distance from the well to the drillsite edge.

Recommendation No. 72: NYCRR and the SGEIS should clarify that setbacks are measured from the edge of the drillsite. Wells should be centered on the well pad and should be set back at least 100' from the pad edge, to maximize well setbacks from sensitive receptors.

[301] 2011 NYSDEC, RDSGEIS, Page 2-34.

19. Disposal of Drilling & Production Waste and Equipment Containing Naturally Occurring Radioactive Material (NORM)

Background: In 2009, HCLLC made recommendations to NYSDEC on best practices for disposal of drilling and production waste and equipment containing Naturally Occurring Radioactive Materials (NORM). NORM includes uranium, thorium, radium, and lead-210 and their decay products.[302] Additionally, radon, a component of natural gas, decays into radioactive polonium.

NORM can be brought to the surface in a number of ways during drilling, completion, and production operations:

- Drilling: Drill cuttings containing NORM are circulated to the surface.
- Completion: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- Production: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

In January 2011, NYSDEC's consultant, Alpha Geoscience, agreed that the disposal of waste containing NORM is an important issue that should be addressed in the SGEIS. Alpha Geoscience's review of HCLLC's recommendations on NORM concluded that:

> *Harvey Consulting's recommendation to analyze practices for NORM testing, NORM treatment, and NORM disposal appears to be complete and well-researched. The review presents a concise analysis of practices involving the testing for and the treatment and disposal of NORM.*
>
> *Harvey Consulting's review of the dSGEIS's content regarding NORM is supported by a range of reliable sources. References include the EPA's website, USGS fact sheets, Texas Railroad Commission regulations, and a publication by Argonne National Laboratory.*[303]

Alpha Geoscience recommended that the SGEIS include a detailed analysis of NORM testing, treatment, transportation, and disposal methods:

> *Alpha suggests that **it may be useful to operators if the SGEIS includes NYSDEC's** detailed analyses of NORM testing, treatment, transportation, and disposal. This information may prove useful to the operator for developing handling and disposal plans [emphasis added].*[304]

[302] USEPA Oil and Gas Production Wastes, NORM, http://www.epa.gov/radiation/tenorm/oilandgas.html.

[303] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 9-11.

[304] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 12.

Yet, Alpha Geoscience recommended against adopting specific regulations to formalize NORM testing, treatment, transportation, and disposal requirements in NYS; instead, Alpha Geoscience recommended that NYSDEC "consider" having "temporary guidelines:"

> *Alpha suggests that NYSDEC consider having temporary guidelines regarding NORM in place, to clarify expectations and requirements for operators prior to the commencement of operations. This also would be helpful to operators for the design of handling and disposal plans [emphasis added].*[305]

HCLLC disagrees with Alpha Geoscience's recommendation for temporary NORM disposal guidelines. The requirements for testing, treatment, transportation, and disposal of NORM should be formalized in NYCRR. The rules should be clear to industry and the public, and enforceable by NYSDEC.

The 2009 DSGEIS acknowledged that drilling and production waste and equipment may contain NORM. NYSDEC reports that the Marcellus Shale contains Uranium-238 and Radium-226, and this NORM may be present in drill cuttings, produced water, and stimulation treatment waste.[306] NYSDEC identified Radium-226 as the most significant NORM of concern, because it is water soluble and has a half-life of 1,600 years.[307] Radiation pathways can include external gamma radiation, ingestion, inhalation of particulates, and radon gas.[308]

In 2009, HCLLC recommended that the SGEIS address the potential for equipment scale and sludge to contain high concentrations of NORM. HCLLC explained that equipment (water lines, flow lines, injection wellheads, vapor recovery units, water storage tanks, heaters/treaters, and separators)[309] used to process natural gas and produced water containing NORM can become coated with radium scale and sludge deposits.[310] Scale precipitates from produced water when it is brought to the surface, cooled to lower temperatures, and subject to lower pressures.[311] The most common form of scale is barium sulfate, which readily incorporates radium in its structure. HCLLC noted that, because E&P waste is exempt from the federal Resource Conservation and Recovery Act (RCRA),[312] it is critical that states establish clear best practice requirements for handling E&P waste, especially for NORM found in equipment scale and sludge. HCLLC pointed out that other oil and gas states, such as Texas and Louisiana, have adopted stringent NORM regulations, including: occupational dose control, surveys; testing and monitoring; record keeping; signs and labeling; and treatment and disposal methods.[313]

[305] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 11.

[306] 2009 NYSDEC, DSGEIS, Page 4-36.

[307] 2009 NYSDEC, DSGEIS, Page 6-129.

[308] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[309] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[310] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[311] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[312] Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, October 2002.

[313] 2009 NYSDEC, DSGEIS, Page 7-101.

The 2011 RDSGEIS: The 2011 RDSGEIS provided some improved data and acknowledged the risk of significant impacts from improperly disposed waste containing NORM. The RDSGEIS concluded that the NORM dataset is limited and there can be significant variability in NORM content. The 2011 RDSGEIS based its conclusions on data collected in other states; this data examined Marcellus Shale cuttings, produced water, and HVHF flowback.

However, the 2011 RDSGEIS still does not establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved in that it establishes radioactive limitations and testing in some cases, but testing is still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g. for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Recommendation No. 73: Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

Equipment Containing NORM: The 2011 RDSGEIS contains substantially improved requirements for equipment containing NORM, including a new radiation testing requirement and a treatment and disposal threshold limit. The RDSGEIS concludes that pipe scale and sludge (NORM buildup in equipment) can result in NORM concentrations that may have a significant adverse impact.

The 2011 RDSGEIS clarifies that NYSDOH will require the well operator to obtain a radioactive materials license for its facility when exposure rate measurements associated with scale accumulation in or on piping, drilling, and brine storage equipment exceeds 50 microR/hr[314] (μR/hr).[315] The RDSGEIS does not explain the origin of the 50 μR/hr limit; however, this limit has been used by a number of oil and gas producing states, including Texas[316] and Louisiana.[317]

[314] Microroentgens per hour (μR/hr) is a measurement of exposure from x-ray and gamma ray radiation in air.

[315] 2011 NYSDEC, RDSGEIS, Page 5-142.

[316] Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, Economic Regulation, Railroad Commission of Texas, Environmental Protection, Oil and Gas NORM.

[317] Louisiana Administrative Code, Title 33 LAC Part XV, Radiation Protection.

Presumably, equipment containing a radioactive concentration of less than 50 µR/hr would be disposed of in a NYS landfill; however, it is unclear if NYS' landfills are designed to accommodate waste containing radioactivity of up to 50 µR/hr.

> Recommendation No. 74: NYSDEC should explain the origin of the 50 µR/hr limit, and explain how NYS determined that this threshold is sufficiently protective for NYS. The SGEIS should explain where equipment containing a radioactive concentration of less than 50 µR/hr would be disposed (e.g. a NYS landfill), and whether this waste disposal method was designed for this waste handling purpose.

The RDSGEIS Chapter 7 (Section 7.7.2) proposes NORM testing (radiation survey) requirements:

> *The Department proposes to require, via permit condition and/or regulation, that radiation surveys be conducted at specified time intervals for Marcellus wells developed by high-volume hydraulic fracturing completion methods on all accessible well piping, tanks, or other equipment that could contain NORM scale buildup. The surveys would be required to be conducted for as long as the facility remains in active use. Once taken out of use no increases in dose rate are to be expected. Therefore, surveys may stop until either the site again becomes active or equipment is planned to be removed from the site. If equipment is to be removed, radiation surveys would be performed to ensure appropriate disposal of the pipes and equipment. All surveys would be conducted in accordance with NYSDOH protocols. The NYSDOH's Radiation Survey Guidelines and a sample Radioactive Materials Handling License are presented in Appendix 27. The Department finds that existing regulations, in conjunction with the proposed requirements for radiation surveys, would fully mitigate any potential significant impacts from NORM [emphasis added].*[318]

NYSDEC's proposal to require NORM testing (radiation surveys) for HVHF wells and equipment is an important improvement. This proposed mitigation measure is effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 65, requires:

> *65) Periodic radiation surveys must be conducted at specified time intervals during the production phase for Marcellus wells developed by high-volume hydraulic fracturing completion methods. Such surveys must be performed on all accessible well piping, tanks, or equipment that could contain NORM scale buildup. The surveys must be conducted for as long as the facility remains in active use. If piping, tanks, or equipment is to be removed, radiation surveys must be performed to ensure their appropriate disposal. All surveys must be conducted in accordance with NYSDOH protocols [emphasis added].*[319]

However, this permit condition is only applied to HVHF wells and equipment. NORM can accumulate in all oil and gas equipment; therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the radiation testing frequency and method be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[320] Furthermore, Dr. Glenn Miller and Dr.

[318] 2011 NYSDEC, RDSGEIS, Page 7-119.

[319] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[320] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

Ralph Seiler recommended that radiation testing not be limited to radium. For example, Dr. Ralph Seiler points out in his comments that while NYSDEC has identified Radium (Ra) as a contaminant of concern, NYSDEC has overlooked the potential significant unmitigated impact of Polonium 210 (^{210}Po) accumulating in pipe scale as a byproduct of radon decay (natural gas contains radon).[321]

> Recommendation No. 75: The requirement for radiation surveys should be codified in the NYCRR and applied to all oil and gas operations, not just HVHF operations. Radiation testing frequency and method should be specified to ensure that all potential radiation impacts are assessed and quantified. The proposed HVHF Permit Condition No. 65 could serve as a starting point for the NYCRR revisions.

Produced Water and Flowback Wastewater NORM: In 2009, HCLLC pointed out that water produced from wells can be rich in chloride, which enhances the solubility of other elements, including the radioactive element radium.[322] HCLLC also noted that flowback wastewater can contain NORM.

In 2009, NYSDEC reported that it had insufficient data on NORM in produced water and flowback wastewater, but acknowledged that NORM is present and is known to be found in elevated levels in produced water.

The Department of Energy (DOE) explains the presence of NORM in produced water:

> *Because the water has been in contact with the hydrocarbon-bearing formation for centuries, it contains some of the chemical characteristics of the formation and the hydrocarbon itself. It may include water from the reservoir, water injected into the formation, and any chemicals added during the production and treatment processes. Produced water is also called "brine" and "formation water." The major constituents of concern in produced water are:*
>
> - *Salt content (salinity, total dissolved solids, electrical conductivity)*
> - *Oil and grease (this is a measure of the organic chemical compounds*[323]
> - *Various natural inorganic and organic compounds or chemical additives used in drilling and operating the well*
> - *Naturally occurring radioactive material (NORM).*
>
> *The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological host formation, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir [emphasis added].*[324]

[321] Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[322] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[323] In addition to the major constituents of concern listed by DOE for produced water, Dr. Glenn Miller notes that both the gasoline and diesel range hydrocarbon fractions should be monitored, since they are more soluble than heavy hydrocarbons.

[324] United States Department of Energy, Produced Water Management Information System, http://www.netl.doe.gov/technologies/pwmis/intropw/index.html.

Since 2009, NYSDEC gathered additional information and improved the 2011 RDSGEIS to acknowledge and quantify the potential adverse impact of produced water radioactivity. Although NYSDEC's research shows that flowback waste may not contain significant concentrations of radioactive material, NYSDEC acknowledges it has a limited dataset, and proposes radiation surveys for both types of wastewater (flowback and produced water).

NYSDEC's proposal to require NORM testing (radiation surveys) for flowback and production brine is a significant improvement to the 2011 RDSGEIS, and this proposed mitigation measure was effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 64, requires:

> *64) Flowback water recovered after high-volume hydraulic fracturing operations must be tested for NORM prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for NORM prior to removal.*[325]

However, this permit condition is only applied to HVHF wells and equipment. NORM can be present in all flowback wastewater, including hydraulic fracture treatments less than 300,000 gallons, and produced water from wells that are not subject to HVHF treatments. Therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the NORM testing method and frequency be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[326]

Recommendation No. 76: The requirement to test produced water (production brine) and flowback wastewater (waste from hydraulic fracturing operations) should by codified in the NYCRR and applied to all oil and gas operations. NORM testing frequency and method should be specified. Proposed HVHF Permit Condition No. 64 could serve as a starting point for NYCRR revisions.

The RDSGEIS proposes to allow flowback wastewater and produced water to be disposed of at a Publically Owned Treatment Works (POTW), as long at the influent concentration of radium-226 (as measured prior to admixture with POTW influent) is limited to 15 pCi/L,[327] or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7.

> *The Department proposes to require, as a permit condition, that the permittee demonstrate that it has a source to treat or otherwise legally dispose of wastewater associated with flowback and production water prior to the issuance of the drilling permit. Disposal and treatment options include publicly owned treatment works, privately owned high volume hydraulic fracturing wastewater treatment and/or reuse facilities, deep-well injection, and out of state disposal.*

[325] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[326] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[327] Picocuries per gram (pCi/g) is a measure of the radioactivity in one gram of a material. One picocurie is that quantity of radionuclide(s) that decays at the rate of 3.7 x 10-2 disintegrations per second.

> *Flowback water and production water must be fully characterized prior to acceptance by a POTW for treatment. Note in particular Appendix C. IV of TOGS 1.3.8, Maximum Allowable Headworks Loading. The POTW must perform a MAHW analysis to assure that the flowback water and production water will not cause a violation of the POTW's effluent limits or sludge disposal criteria, allow pass through of unpermitted substances or inhibit the POTW's treatment processes. As a result, the SPDES permits for POTWs that accept this source of wastewater will be modified to include influent and effluent limits for Radium and TDS, if not already included in the existing SPDES permit, as well as for other parameters as necessary to ensure that the permit correctly and completely characterizes the discharge. In the case of NORM, anyone proposing to discharge flowback or production water to a POTW must first determine the concentration of NORM present in those waste streams to determine appropriate treatment and disposal options. POTW operators who accept these waste streams are advised to limit the*
>
> *concentrations of NORM in the influent to their systems to prevent its inadvertent concentration in their sludge. For example, due to the potentially large volumes of these waste waters that could be processed through any given POTW, as well as the current lack of data on the level of NORM concentration that may take place, it will be proposed that POTW influent concentrations of radium-226 (as measured prior to admixture with POTW influent) be limited to 15 pCi/L, or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7. As more data become available on concentrations in influent vs. sludge it is possible that this concentration limit may be revisited [emphasis added].*[328]

EPA data shows that produced water can contain 0.1 to 9,000 pCi/L of radium-226.[329] Therefore, it is reasonably foreseeable that there will be substantial volumes of wastewater that will exceed the 15 pCi/L POTW influent limit. NYSDEC has not proposed a waste treatment or disposal solution for wastewater that exceeds the 15 pCi/L POTW influent limit.

> Recommendation No. 77: The SGEIS should examine treatment and disposal options, and capacity within NYS, for wastewater exceeding 15 pCi/L radiation.

Additionally, it is unclear if NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation. The Federal Safe Drinking Water standard is 5 pCi/L[330] (radium-226 and radium -228 combined).[331] The 5 pCi/L threshold was set because of the increased risk of cancer above this level. Because the RDSGEIS does not examine NYS' POTW's ability to treat incoming wastewater with 15 pCi/L radiation, it does not provide an estimate of the expected radiation level at the POTW effluent. Therefore, it is not clear whether POTW effluent discharge at a level greater than 5 pCi/L could end up in a drinking water supply, or how NYSDEC plans to monitor and ensure that this does not happen.

[328] 2011 NYSDEC, RDSGEIS, Page 6-58 and 6-59.

[329] USEPA Oil and Gas Production Wastes, Summary Table of Reported Concentrations of Radiation in TENORM, http://www.epa.gov/radiation/tenorm/sources.html#summary-table

[330] Measured as Radium 226 and Radium 228 combined.

[331] USEPA Federal Safe Water Drinking Water Standards for Radionuclides at http://water.epa.gov/drink/contaminants/index.cfm#List.

Recommendation No. 78: The SGEIS should examine whether NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation, and should predict the maximum effluent radiation level. The SGEIS should explain how NYSDEC will ensure that drinking water sources will not exceed 5 pCi/L radiation.

The 2011 RDSGEIS does not prohibit road spreading of waste; it deferred this decision to a yet-to-be determined future process outside the SGEIS review. Yet, other oil and gas producing states, such as Texas, specifically prohibit road spreading of waste containing NORM.[332] A study conducted by Argonne National Lab for the US Department of Interior (DOI) concluded that land spreading of diluted NORM waste presented the highest potential dose of exposure to the general public of all waste disposal methods studied.[333]

Most states dispose of wastewater using deep well injection or use it to enhance hydrocarbon recovery operations. Land disposal is not common for onshore operations. The Department of Energy reports that more than 98% of oil and gas wastewater from onshore operations is injected into underground disposal wells, which are regulated by EPA, or used for enhanced hydrocarbon recovery.[334] The 2009 DSGEIS explored produced water treatment and disposal options (e.g. injection wells, treatment plants, and road spreading),[335] but did not land on a best practice.

The 2011 RDSGEIS concludes there is not enough information available to allow for road spreading under a Beneficial Use Determination (BUD).[336] However, the RDSGEIS does not explicitly state that road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

Since the current BUD does not require an operator to test for NORM,[337] it is unclear how NORM testing at the well site will be integrated into the BUD process. The level of NORM, if any, that will be allowed in fluids used for road spreading is also unclear. The 2011 RDSGEIS does not examine the cumulative impact of spreading small amounts of NORM repeatedly over the same area. It is recommended that land and road spreading of produced water and other waste containing NORM be prohibited. Produced water containing NORM should be returned to the subsurface formation from which it came, or should be handled at an approved waste treatment plant.

Recommendation No. 79: The SGEIS should explicitly state that land and road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

[332] Texas Railroad Commission (TXRRC), 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632. "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes.

[333] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[334] Argonne National Laboratory, Produced Water Volumes and Management Practices in the United States, Report Prepared for United States Department of Energy, Report No. ANL/EVS/R-09/1, 2009.

[335] 2009 NYSDEC, DSGEIS, Page 5-131.

[336] 2011 NYSDEC, RDSGEIS, Page 7-60.

[337] The example BUD application provided in Appendix 12 requires testing for calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil and grease, benzene, ethylbenzene, toluene and xylene, but not NORM.

The Environmental Protection Agency (EPA) identifies produced water pits (brine pits) as an outdated practice in cases where produced water contains NORM. If wastewater pond sediments pose a potential radiological health risk, tank sediments from wastewater stored in tanks also would pose a radiological health risk. EPA reports that:

> *Lined and/or earthen pits were previously used for storing produced water and other nonhazardous oil field wastes, hydrocarbon storage brine, or mining wastes. In this case, TENORM[338] in the water will concentrate in the bottom sludges or residual salts of the ponds. Thus the pond sediments pose a potential radiological health risk....produced waters are now generally reinjected into deep wells…No added radiological risks appear to be associated with this disposal method as long as the radioactive material carried by the produced water is returned in the same or lower concentration to the formations from which it was derived [emphasis added].*[339]

Recommendation No. 80: The SGEIS should address testing of wastewater sediments, and explain the collection, transportation, treatment, and disposal methods for this potential radiological health risk.

Drill Cutting NORM: The 2011 RDSGEIS acknowledges the fact that drill cuttings can contain NORM, but makes a blanket assumption that the level of radiation from cuttings will be low. The RDSGEIS does not require site-specific testing to verify this assumption, nor does it preclude cuttings disposal in existing solid waste landfills. Instead, the RDSGEIS only recommends that the well operator consult with the landfill operator prior to drill cuttings disposal.

> *In New York State the NORM in cuttings is not precluded by regulation from disposal in a solid waste landfill, though well operators should consult with the operators of any landfills they are considering using for disposal regarding the acceptance of Marcellus Shale drill cuttings by that facility [emphasis added].*[340]

The 2011 RDSGEIS is unclear about the environmental and human health protections that would be achieved via the landfill consultation process. Appendix 10, Proposed EAF Addendum Requirements for HVHF, requires the operator to specify where it plans to dispose of cuttings, and requires evidence that the cuttings will go to a Part 360 solid waste landfill. However, the RDSGEIS does not provide scientific or engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM.

NYSDEC acknowledges significant uncertainty about the NORM content of drill cuttings in Chapter 7, and raises questions as to whether there are sufficient data to fully assess NORM impacts at this time. The 2011 RDSGEIS states:

> *Existing data from drilling in the Marcellus Formation in other States, and from within New York for wells that were not hydraulically fractured, shows significant variability in NORM content. This variability appears to occur both between wells in different portions of the formation and at a given well over time. This makes it important that samples from wells in different locations within New York State are used to assess the extent of this variability.*

[338] TENORM is Technologically Enhanced Natural Occurring Radioactive Material.

[339] http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.

[340] 2011 NYSDEC, RDSGEIS, Page 5-129 and 5-130.

> *During the initial Marcellus development efforts, sampling and analysis would be undertaken in order to assess this variability. These data would be used to determine whether additional mitigation is necessary to adequately protect workers, the general public, and environment of the State of New York [emphasis added].*[341]

Yet, the 2011 RDSGEIS does not propose NORM mitigation measures. It does not require drill cuttings testing prior to disposal in the landfill, nor does it establish a maximum allowed NORM disposal threshold for safe long-term cuttings disposal in a landfill.

Recommendation No. 81: Drill cuttings should be tested for NORM prior to disposal in a landfill. A maximum allowed NORM threshold for drill cuttings disposal in the landfill should be clearly established and scientifically justified. Testing and threshold requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Waste exceeding the established NORM threshold should be handled under NYS' radioactive waste handling rules.

Chapter 5.2.4.2 of the 2011 RDSGEIS concludes that NORM content in drill cuttings is equivalent to background levels of radiation occurring naturally in the atmosphere. This conclusion is based on Geiger counter and gamma ray spectroscopy sampling methods.

Yet, Dr. Glenn Miller points out in his comments on the 2011 RDSGEIS[342] that gamma ray spectroscopy is insufficient to assess all radioactive constituents (e.g. polonium is radioactive and only a weak gamma ray emitter), and gamma ray measurements do not provide insight into the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate NORM when disposed. Dr. Miller concludes that NYS likely has underestimated the amount of NORM in drill cuttings, and recommends NYS require additional testing methods to verify total radiation levels and better understand the potential for drill cuttings to later oxidize, leach, and concentrate NORM when disposed. Additional work is needed to verify whether the disposal of drill cuttings containing NORM in existing NYS landfills is a best practice.

Recommendation No. 82: The SGEIS should provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, including lower concentrations of NORM that could cumulatively have a significant impact when stored in large volumes over long periods of time. The SGEIS should examine the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate radioactive materials within the landfill. If NYSDEC cannot provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, it should identify alternative collection, transportation, treatment, and disposal requirements.

NYCRR Proposed Revisions: Proposed Permit Condition No. 53 requires waste fluids be handled in accordance with 6 NYCRR § 554.1(c)(1); yet, this regulation does not specify the best practice for handling hydraulic fracturing fluid and other drilling and completion wastes. Instead, 6 NYCRR § 554.1(c)(1) merely provides a process for the applicant to submit a waste management plan. In 2009, HCLLC recommended revisions to this regulation; yet, none are proposed. The existing regulation states:

> *Prior to the issuance of a well-drilling permit for any operation in which the probability exists that brine, salt water or other polluting fluids will be produced or obtained during drilling operations in sufficient quantities to be deleterious to the surrounding environment, the operator*

[341] 2011 NYSDEC, RDSGEIS, Page 7-119.

[342] Miller, G., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

> *must submit and receive approval for a plan for the environmentally safe and proper ultimate disposal of such fluids. For purposes of this subdivision, drilling muds are not considered to be polluting fluids. Before requesting a plan for disposal of such fluids, the department will take into consideration the known geology of the area, the sensitivity of the surrounding environment to the polluting fluids and the history of any other drilling operations in the area. Depending on the method of disposal chosen by the applicant, a permit for discharge and/or disposal may be required by the department in addition to the well-drilling permit. An applicant may also be required to submit an acceptable contingency plan, the use of which shall be required if the primary plan is unsafe or impracticable at the time of disposal [emphasis added].*

Terms such as "sufficient quantities" are ambiguous, providing operators and regulators large latitude in how they interpret the regulation. Regulations should specify technically and scientifically based thresholds and management practices.

Under 6 NYCRR § 554.1(c)(1), the waste disposal method is selected by the applicant, with no instruction on how to determine the best waste management practice. While recycling and the reuse of fracturing fluid are discussed in the RDSGEIS, there is no requirement in the proposed permit conditions to use this best practice. Furthermore, NYSDEC does not explain how it will oversee the recycling and reuse processes.

Recommendation No. 83: Revisions are needed to 6 NYCRR § 554.1(c)(1) to require a more robust waste management planning and oversight process, including detailed instructions on collection, testing, transportation, treatment, and disposal of waste.

20. Hydrogen Sulfide

Background: In 2009, HCLLC recommended that the NYCRR require operators to follow American Petroleum Institute Recommended Practice 49 (API RP 49) for Drilling and Well Servicing Operations Involving Hydrogen Sulfide, and API RP 55 for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, to protect employees and the public.

The 2011 RDSGEIS: The 2011 RDSGEIS reports that Marcellus Shale operations in Pennsylvania have not produced substantial amounts of H_2S.[343] However, this conclusion is based on limited information from wells drilled only in Pennsylvania. These data do not confirm that H_2S will not be present initially or over time in NYS wells.

H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause serious health symptoms at elevated concentrations, and can be deadly at the higher concentrations found in some oil and gas wells.

The Occupational Safety and Health Administration (OSHA) recommends close monitoring of H_2S for human health and explosion mitigation:

> *Hydrogen Sulfide or sour gas (H2S) is a flammable, colorless gas that is toxic at extremely low concentrations. It is heavier than air, and may accumulate in low-lying areas. It smells like "rotten eggs" at low concentrations and causes you to quickly lose your sense of smell. Many areas where the gas is found have been identified, but pockets of the gas can occur anywhere.*
>
> *Iron sulfide is a byproduct of many production operations and may spontaneously combust with air.*
>
> *Flaring operations associated with H_2S production will generate Sulfur Dioxide (S02), another toxic gas.*
>
> *Active monitoring for hydrogen sulfide gas and good planning and training programs for workers are the best ways to prevent injury and death.*[344]

The American Conference of Governmental Industrial Hygienists recommends a Threshold Limit Value of 10ppm and a short-term exposure (STEL) limit of 15 ppm, averaged over 15 minutes, for the action level indicating the need for respiratory protection.[345] While workers may be afforded respiratory protection, nearby members of the public do not have routine access to respiratory protection and monitoring systems. Routine, standardized testing should also be in place to ensure public health and safety.

A 300 ppm concentration of H_2S is considered by the American Conference of Governmental Industrial Hygienists as Immediately Dangerous to Life and Health.

[343] 2011 NYSDEC, RDSGEIS, Page 5-138.

[344] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/h2s_monitoring.html.

[345] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html.

> *In low concentrations, H_2S sometimes can be detectable by its characteristic odor; however, the smell cannot be relied upon to forewarn of dangerous concentrations (greater than 100ppm) of the gas because it rapidly paralyzes the sense of smell due to paralysis of the olfactory nerve. A longer exposure to the lower concentrations has a similar desensitizing effect on the sense of smell.*
>
> *It should be well understood that the sense of smell will be rendered ineffective by hydrogen sulfide, which can result in an individual failing to recognize the presence of dangerously high concentrations. Exposure to hydrogen sulfide causes death by poisoning the respiratory system at the cellular level.* [346]

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public.

While H_2S may not be initially present at a drillsite, the operator must remain vigilant in monitoring for H_2S over time, because sulfate reducing bacteria and other forms of acid producing bacteria can generate H_2S in the reservoir, such that H_2S concentrations elevate over time. Increasing levels of H_2S is a common problem in waterflooding operations in oil and gas fields. Biocides are typically used to mitigate bacteria growth; however, sometimes biocides are not successful.

Biocide use and close monitoring of H_2S early in field development is an important mitigation measure, because once elevated H_2S is present it is difficult to control. Industry anticipates H_2S will be a future concern in operations requiring large volumes of water for HVHF treatments, especially where treatment fluid is recycled, as planned in NYS. A 2010 Apache Corporation paper summarizes the problem:

> *One of the most severe threats in recycling waters for fracs is the control of bacteria (Tischler, 2009), including sulfate reducing bacteria (SRBs) and other forms such as acid producing bacteria (APB), iron fixing bacteria and slime formers. SRBs have created souring of some conventional reservoirs from injection of waters, both produced and semi-fresh, which have established a presence in the reservoirs and create H_2S gas and iron sulfide problems. Local well fouling problems are common where SRBs are spiked into the formation from drilling or completion fluids. This type of H_2S occurrence may cause local corrosion…in shale, however, the effect of uncontrolled bacteria is a general unknown, given the extremely large volumes of surface water used for slick water fracturing. For this reason, recycling of the water may seed all waters with bacteria and/or concentrate the bacteria; thus bacterial control is a necessity [emphasis added].* [347]

Due to the potential close proximity of Marcellus Shale operations to the public, a robust initial monitoring program should be instituted to determine H_2S concentrations in Marcellus Shale gas throughout NYS. As described in American Petroleum Institute Recommended Practices 49 and 55, monitoring frequency can be adjusted over time as site-specific information is obtained. Initial sampling should be conducted at each drillsite, with at least monthly sampling thereafter.

[346] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html

[347] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010, Page 30.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing, Permit Condition No. 25 includes a requirement to conform with API RP 49; however, there is no requirement for operators to conform with API RP 55, which applies after the well is drilled, during production operations.

NYCRR Proposed Revisions: As a control measure, when H_2S is present, the proposed regulations at 6 NYCRR § 560.6(c)(28) require the venting of any gas containing H_2S through a flare stack to combust the dangerous vapors.

Recommendation No. 84: H_2S monitoring and reporting requirements should be included in the RDSGEIS as a mitigation measure and codified in the NYCRR. Operators should be required to follow H_2S detection and handling procedures to protect employees and the public. Initial H_2S testing should be conducted at each drillsite. Subsequent test frequency should be based on the results of initial testing. H_2S levels can increase over time as gas fields age and sour. H_2S requirements should be included in regulation for both drilling and production operations, and should not just be relegated to a drilling permit condition. Additionally, when H_2S is present, nearby neighbors, local authorities, and public facilities should be notified, and provided information on the safety and control measures that the operator will undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

21. Chemical & Waste Tank Secondary Containment

Background: In 2009, HCLLC recommended that NYCRR be revised to include secondary containment for chemicals stored on the well pad or, alternatively, require the use of double-wall tanks. Chemicals, especially corrosive chemicals, can result in storage container leaks and spills to the environment. Best practice for permanent chemical storage is to install secondary containment under the storage container, and ensure the containers are not in contact with soil or standing water.[348] Shale gas drilling and HVHF operations include the use of many chemical tanks and waste handling tanks (e.g. flowback tanks) that warrant secondary containment.

2011 RDSGEIS: NYSDEC responded to public comments and made appropriate revisions to the 2011 RDSGEIS with its requirement for 110% secondary containment for all chemical and waste handling tanks. It also requires secondary containment for chemical and waste transport, mixing and pumping equipment. The 2011 RDSGEIS states:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[349]
>
> *Secondary containment would be required for all fracturing additive containers and additive staging areas. These requirements would be included in supplementary well permit conditions for high-volume hydraulic fracturing.*[350]
>
> *Secondary containment measures may include one or a combination of the following; dikes, liners, pads, curbs, sumps, or other structures or equipment capable of containing the substance. Any such secondary containment would be required to be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area.*[351]
>
> *Secondary containment for flowback tanks is required.*[352]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[353]
>
> *Location of additive containers and transport, mixing and pumping equipment...within secondary containment...[emphasis added]*[354]

[348] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.

[349] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[350] 2011 NYSDEC, RDSGEIS, Page 7-38.

[351] 2011 NYSDEC, RDSGEIS, Page 7-38.

[352] 2011 NYSDEC, RDSGEIS, Page 7-40.

[353] 2011 NYSDEC, RDSGEIS, Page 1-12.

[354] 2011 NYSDEC, RDSGEIS, Page 7-29.

Recommendation No. 85: Secondary containment requirements for well site chemicals should be applied as a best practice to all oil and gas development and codified in NYCRR, and should not be limited to shale gas and HVHF operations.

NYCRR Proposed Revisions: Proposed regulations codify the requirement for secondary containment for chemical and waste handling tanks, but do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment.

Recommendation No. 86: Consistent with the proposed RDSGEIS mitigation, 6 NYCRR § 750-3.11 and 6 NYCRR § 560.6 should be revised to require lined secondary containment for chemical and waste transport, mixing, and pumping equipment.

Proposed regulations at 6 NYCRR § 750-3.11 provide very specific instructions on how to construct adequate secondary containment, including the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. Regulations also state that the containment structures must have adequate freeboard, be protected from damage, and be able to contain at least 110% of the largest tank volume.

> *750-3.11 Applications of standards, limitations and other requirements*
>
> *(e) The HVHF SWPPP must, at a minimum, include the HVHF SWPPP General Requirements listed in subparagraph (1) below, Structural Best Management Practices (BMPs), Non-structural BMPs, and Activity-Specific SWPPP Requirements.*
>
> *(v) Secondary Containment - To prevent the discharge of hazardous substances, the owner or operator shall provide, implement, and operate secondary containment measures. Such secondary containment shall be: (a) designed and constructed in accordance with good engineering practices, (b) constructed, coated or lined with materials that are chemically compatible with the environment and the substances to be contained, (c) provide adequate freeboard, (d) protected from heavy vehicle or equipment traffic; and have a volume of at least 110 percent of the largest storage tank within the containment area [emphasis added].*

In contrast, proposed regulations at 6 NYCRR § 560.6 offer substantially less instruction on how to construct adequate secondary containment. They do not mandate the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. They do not require the containment structure have adequate freeboard. Nor do they require that the containment be protected from damage.

> *§560.6 Well Construction and Operation.*
>
> *(c) Drilling, Hydraulic Fracturing and Flowback.*
>
> *(26) Hydraulic fracturing operations must be conducted as follows:*
>
> *(i) secondary containment for fracturing additive containers and additive staging areas, and flowback tanks is required. Secondary containment measures may include, as deemed appropriate by the department, one or a combination of the following: dikes, liners, pads, impoundments, curbs, sumps or other structures or equipment capable of containing the substance. Any such secondary containment must be sufficient to contain*

> *110 percent of the total capacity of the single largest container or tank within a common containment area. No more than one hour before initiating any hydraulic fracturing stage, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order [emphasis added].*

Recommendation No. 87: 6 NYCRR § 560.6 should be revised to include specific secondary containment construction standards that are consistent with 6 NYCRR § 750-3.11.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing: Permit conditions have been developed to require secondary containment. However, the permit conditions merely echo proposed regulations at 6 NYCRR § 560.6. They do not provide additional or supplemental requirements to the NYCRR.

Recommendation No. 88: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing contained in the RDSGEIS to remove requirements that are redundant with NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

22. Fuel Tank Containment

Background: In 2009, HCLLC recommended that the NYCRR be revised to require more stringent oil spill prevention measures for temporary fuel tanks associated with drilling and well stimulation activities, and that NYS' regulations be at least as stringent as federal EPA's Spill Prevention Control and Countermeasures (SPCC) Plan. HCLLC recommended that NYSDEC incorporate existing EPA oil spill prevention standards into the NYCRR. EPA standards require secondary containment if a facility stores 1,320 gallons of fuel or more (30 CFR § 112), including portable, temporary fuel tanks.

In 2009, NYSDEC proposed to exempt drilling rig and HVHF fuel tanks (even those as large as 10,000 gallons) from NYS' petroleum bulk storage regulations and tank registration requirements at 6 NYCRR §§ 612-614, citing the fact that the storage tanks are temporary (non-stationary) as the reason for the exemption. This problem persists in the 2011 RDSGEIS.

HCLCC questioned NYSDEC's rationale for exempting drilling rig and HVHF fuel tanks from NYS' spill prevention regulations, as all other tanks 1,100 gallons and larger must register in NYS, install secondary containment, and undergo inspections at 5- and 10-year intervals.

HCLLC pointed out that a temporary fuel tank poses a greater environmental risk than a stationary fuel tank, because temporary fuel tanks are relocated many times during their operating lives, increasing the potential for tank damage during transit and the likelihood of tank appurtenance leakage.

Large temporary fuel tanks should be subject to the same secondary containment requirements as large stationary fuel tanks in NYS, particularly in situations where temporary fuel tanks are installed in one location for a significant period of time (e.g. a multi-well pad where drilling and completion operations could span several years). Alternatively, where secondary containment is not technically feasible, the use of double-walled or vaulted tanks should be considered for portable fuel tanks.

In January 2011, NYS' consultant, Alpha Geoscience, reviewed HCLLC's recommendation and provided NYSDEC with incorrect guidance on EPA's secondary containment requirements for onshore oil drilling workover and mobile equipment and other fuel storage.[355] Alpha Geoscience advised NYSDEC that EPA's SPCC regulations only addressed stationary fuel tanks greater than 1,320 gallons.

Alpha Geoscience's advice was incorrect because EPA's SPCC rules apply to facilities that have an aggregate fuel or hydrocarbon storage of 1,320 gallons or more at a facility, and secondary containment rules are not limited to stationary tanks.[356]

2011 RDSGEIS: NYSDEC's 2011 proposal for fuel tank secondary containment is confusing and inconsistent. The RDSGEIS both recommends and requires fuel tank secondary containment as a best practice, yet also exempts large fuel tanks used for drilling and HVHF operations.

For example, the 2011 RDSGEIS states that secondary containment will be required for fuel tanks and areas where fuel transfers occur:

[355] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 21.

[356] USEPA, SPCC Guidance for Regional Inspectors Version 1.0, November 28, 2005, Page 2-16.

> *The Department proposes to require, via permit condition and/or new regulation, that operators provide secondary containment around all additive staging areas and fueling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans [emphasis added].*[357]

NYSDEC supports its recommendation for fuel tank secondary containment by pointing out that its consultant has identified it as a best management practice:

> *In addition to its regulatory survey, Alpha also reviewed and discussed best management practices directly observed in the northern tier of Pennsylvania and noted that "[t]he reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York." The best management practices referenced by Alpha* ***include…Secondary containment structures around petroleum storage tanks and lined*** *trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination [emphasis added].*[358]

Yet, the 2011 RDSGEIS exempts large fuel tanks from secondary containment by designating drilling rig and HVHF fuel tanks as "temporary":

> *The diesel tank fueling storage associated with the larger rigs described in Chapter 5 may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad. However, the tank would be removed along with the rig during any drilling hiatus between wells or after all the wells have been drilled. There are no long-term or permanent operations at a drill pad which require an on-site fueling tank. Therefore, the tank is considered non-* ***stationary and is exempt from the Department's petro****leum bulk storage regulations and tank registration requirements [emphasis added].*[359]

The 2011 RDSGEIS does not explain why a temporary fuel tank would pose less risk of a spill than a stationary fuel tank.

The 2011 RDSGEIS further confuses the issue by stating that all fuel tanks would be included in secondary containment:

> *The following measures are proposed to be required, via permit condition and/or regulation, to prevent and mitigate spills. For all wells subject to the SGEIS, supplementary permit conditions for high-volume hydraulic fracturing would include the following requirements with respect to fueling tanks and refilling activities:*
>
> > *a. Secondary containment consistent with the objectives of SPOTS 10 for all fueling tanks.*
> >
> > *The secondary containment system could include one or a combination of the following: dikes, liners, pads, holding ponds, curbs, ditches, sumps, receiving tanks or other equipment capable of containing spilled fuel. Soil that is used for secondary containment would be of such character that a spill into the soil will be readily recoverable and would result in a minimal amount of soil contamination and*

[357] 2011 NYSDEC, RDSGEIS, Page 1-11.

[358] 2011 NYSDEC, RDSGEIS, Page 8-5.

[359] 2011 NYSDEC, RDSGEIS, Page 7-343.

> *infiltration. Draft Department Program Policy DER-1730 may be consulted for permeability criteria for dikes and dike construction standards, including capacity of at least 110% of the tank's volume [emphasis added].*[360]

Ultimately, the 2011 RDSGEIS, includes secondary containment requirements for all fuel tanks, in Appendix 10, Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing.

> *13) Secondary containment consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks,(SPOTS 10) is required for all fueling tanks [emphasis added];*
>
> *14) To the extent practical, fueling tanks must not be placed within 500 feet of a public or private water well, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond;*
>
> *15) Fueling tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and;*
>
> *16) Troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment.*[361]

While, it is useful that the RDSGEIS finally lands on requiring secondary containment for fuel tanks, there remains a conflict in the text where NYSDEC has proposed to exempt temporary fuel tanks.

Recommendation No. 89: The SGEIS text should be revised to remove the temporary fuel tank exemption from secondary containment described on page 7-34.

Additionally, Appendix 10 permit conditions merely echo proposed regulations at 6 NYCRR § 560.6, and do not provide additional or supplemental requirements to the NYCRR. Therefore, if adopted into regulation, the permit conditions could be streamlined.

Recommendation No. 90: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing to remove requirements that are redundant with the proposed revisions to NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 codify the requirement for fuel tank secondary containment, and set no limit on the size or duration of fuel tank use. These proposed regulations are protective of the environment. The RDSGEIS should be revised to be consistent with the proposed regulations, avoiding future confusion about NYSDEC's intent.

> §560.6 Well Construction and Operation.
>
> *(b) Site Maintenance.*
>
> *(1) For any well:*

[360] 2011 NYSDEC, RDSGEIS, Page 7-34.

[361] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 3.

(i) secondary containment is required for all fueling tanks [emphasis added];

(ii) to the extent practical, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond;

(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.

Recommendation No. 91: The SGEIS should be revised to be consistent with the proposed regulations, which require secondary containment for all fuel tanks (6 NYCRR § 560.6) used for shale gas drilling and HVHF operations.

While proposed regulations at 6 NYCRR § 560.6 are useful because they make it clear that secondary containment is required for all fuel tanks, the proposed regulations do not provide specific instruction on how to construct adequate containment.

Recommendation No. 92: 6 NYCRR § 560.6 should be revised to clearly state that all fuel tank secondary containment should be designed and constructed in accordance with good engineering practices, incremental to the minimum federal standards. Good engineering practices include: using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 require a 500' setback for fuel tanks from perennial or intermittent streams, storm drains, wetlands, lakes, and ponds, but only to the "extent practical" with no explanation of what that means in real terms, and under what conditions it would be acceptable to place a fuel tank closer. NYCRR does not include any setbacks from homes or public facilities.

§560.6 Well Construction and Operation.

(b) Site Maintenance.

(1) For any well:

(i) secondary containment is required for all fueling tanks;

(ii) to the extent practical, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond[emphasis added];

(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.

Recommendation No. 93: Proposed regulations at 6 NYCRR § 560.6 (b)(1)(ii) should be revised to delete the term "to the extent practical," and should include minimum setbacks for fuel tanks from homes and public buildings.

Additionally, the RDSGEIS is problematic because it still references a draft NYSDEC Program Policy (DER-17) for construction standards and a September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on secondary containment construction.

Recommendation No. 94: The SGEIS should not rely on a draft[362] NYSDEC Program Policy document (DER-17) for construction standards and an outdated September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on secondary containment construction. Instead, secondary containment requirements for fuel tanks should be codified in the NYCRR and written in a way that is clear, consistent, and enforceable.

The importance of secondary containment for fuel tanks extends beyond shale gas drilling and HVHF operations to all hydrocarbon drilling and HVHF operations.

Recommendation No. 95: Secondary containment requirements for fuel tanks should extend to all hydrocarbon drilling and HVHF operations in NYS. The requirements should not be limited to shale gas drilling and HVHF operations. Therefore, the recommendations made above should be captured in both 6 NYCRR § 560 and 6 NYCRR § 554.

The RDSGEIS does not cite existing EPA spill prevention requirements at 40 CFR § 112, which apply to all fuel tanks, including drilling tanks, at 40 CFR § 112.7(c) and 40 CFR § 112.10(c). EPA's regulations, which were revised in 2002, require secondary containment for fuel tanks at facilities storing 1,320 gallons and more. EPA allows an operator the opportunity to demonstrate under 40 CFR § 112.7(d) that it is impracticable to install secondary containment; however, EPA requires a formal written "impracticability determination." Under this determination, EPA requires periodic tank integrity testing, leak testing of the valves and associated piping, a Part 109 contingency plan, and a written commitment of manpower, equipment, and materials to respond to a spill.

Recommendation No. 96: The SGEIS should cite federal standards (similar to how NYSDEC cited relevant USEPA standards for air quality) and notify the operator that the federal standards must be met. The SGEIS should also clearly explain what additional requirements will be imposed by NYS.

The RDSGEIS should also include: periodic fuel tank inspections to examine structural conditions and document corrosion or damage; the installation of high-liquid-level alarms that sound and display in an immediately recognizable manner; the installation of high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 97: In the NYCRR, NYSDEC should require tank inspections and tank alarm systems.

[362] If NYSDEC decides to refer to policy and guidance documents, those documents at a minimum should be final documents, and NYSDEC should state within those documents that the contents are enforceable.

NYSDEC does not address whether vaulted, double-walled, or self-diking tanks can be used as alternatives to constructing large temporary containment areas. Other oil and gas producing states allow the use of vaulted, self-diking, or double-walled portable tanks to meet the secondary containment requirement in cases where the operator can demonstrate that it is infeasible to install a containment area meeting EPA's 110% of the largest tank volume requirement. NYSDEC could consider allowing these alternative tanks in places where secondary containment is proven to be infeasible.

Vaulted, self-diking, and double-walled portable tanks are equipped with catchments that hold fuel overflow or divert it into an integral secondary containment area. Industry standards for the construction of vaulted, self-diking, and double-walled portable tanks include:

- Underwriters Laboratories' Steel Aboveground Tanks for Flammable and Combustible Liquids (UL 142);
- Appendix J of the American Petroleum Institute's (API) Welded Steel Tanks for Oil Storage (API 650); and
- API's Specification for Shop Welded Tanks for Storage of Production Liquids (API Spec 12F).

Due to the higher potential for damage during relocation and use at multiple sites, it is recommended that inspections be routinely performed on vaulted, self-diking, and double-walled portable tanks. The inspections should identify damage and corrosion using one of the following standards:

- Steel Tank Institute's (STI) Standard for the Inspection of Aboveground Storage Tanks, Third Edition (STI SP00l); or
- API's Tank Inspection, Repair, Alteration, and Reconstruction Standard (API 653).

As an oil spill prevention measure, portable tanks can be equipped with high-liquid-level alarms that sound and display in an immediately recognizable manner; high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 98: NYSDEC should clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed, and codify in the NYCRR the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

23. Corrosion & Erosion Mitigation & Integrity Monitoring Programs

Background: In 2009, HCLLC recommended that NYSDEC require corrosion and erosion mitigation programs. More specifically HCLLC recommended that: equipment be designed to prevent corrosion and erosion; monitoring programs be put into place to identify corrosion and erosion over the well and equipment operating lifetime; and repair and replacement of damaged wells and equipment be completed.

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in oil and gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide (CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves.

HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The 2011 RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require facilities be designed to resist corrosion (e.g. material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment.[363]

As explained in Chapter 20 of this report, the use of recycled HVHF fluid can result in the inoculation of sulfate reducing bacteria in the reservoir, and increased downhole equipment corrosion. And, while NYSDEC indicates that H_2S levels may be initially low in the Marcellus Shale, this may not be the case during the full life-cycle of the well. Nor does the RDSGEIS examine the H_2S of all other low permeability gas reservoirs to know what the H_2S might be for those formations.

Corroded well casings can provide a pathway for gas and well fluids to leak into protected aquifers. Therefore, it is important to install a robust casing system, and it's equally important to ensure that the casing system's integrity is maintained during the well's life.

Corrosion measured on production casing is an important piece of information, because corrosive fluids are known to also degrade the quality of the cement barrier. Corrosive fluids reduce the cement strength and make it more permeable, potentially providing a pathway for hydrocarbons to migrate from zones of higher pressure to lower pressure freshwater zones.

Additionally, the bond between the casing and cement can be compromised over the well's life, creating a "micro-annulus" (a space between the outer pipe wall and cement sheath) that allows vertical migration of hydrocarbons along the outside of the pipe wall. [364,365] Micro-annulus' can be formed during initial

[363] Curran, E., Corrosion Control in Gas Pipelines, Coating Protection Provides a Lifetime of Prevention, Pipeline & Gas Journal, October 2007.

[364] See Ravi, K. (Halliburton), Bosma, M. (Shell) and Gastebled, O. (TNO Building and Construction Research), Safe and Economic Gas Wells through Cement Design for the Life of the Well, Society of Petroleum Engineering Paper No. 75700, 2002. Ravi et. al. concludes: "The extreme operating conditions that occur in gas-storage and gas-producing wells could cause the cement sheath to fail, resulting in fluid migration through the annulus…The sustained casing pressure observed on a number of wells after they have been put on production emphasizes the need to design a cement sheath that will maintain integrity during the life of the well…However, recent experience has shown that after well operations such as completing, pressure testing, injecting, stimulating and producing, the cement sheath could lose its ability to provide zonal isolation. This failure can create a path for formation fluids to enter the annulus, which pressurizes the well and renders the well unsafe to operate…Failure of the cement sheath is most often caused by pressure – or temperature-induced stresses inherent in well operations during the well's economic life."

cementing, or later in the well's life, due to: pipe wall thinning; cement deterioration; the shock of additional well workover activities (perforations, stimulation, drilling); pressure and temperature changes in the well; or by seismic vibrations.

In January 2011, NYS' consultant, Alpha Geoscience, recommended that NYSDEC ignore HCLLC's best practice recommendations for corrosion and erosion, citing Section 6.1.4.2 and 6.1.5.1 of the 2009 DSGEIS. In these sections, another NYS consultant (ICF) estimated the risk of groundwater contamination due to casing failure in a Class II injection well is 1 in 50 million wells.[366] Alpha Geoscience concludes that corrosion and erosion prevention, monitoring, and repair requirements are unnecessary in the NYCRR.

Neither Alpha Geoscience nor ICF provide technical justification for the use of a Class II injection well corrosion risk analysis as a surrogate for a gas well corrosion risk analysis. A Class II injection well risk profile is different than a gas well. Gas wells can continuously produce sources of corrosive gas (CO_2 and H_2S), water, and sediment, that can corrode and erode well casing and surface piping over time.

Neither Alpha Geoscience nor ICF examined:

- The full life cycle of a gas well, and the fact that there is substantial field evidence that well casings do corrode and erode over time;
- The fact that casing inspection logs, caliper logs, temperature surveys, and other wellbore diagnostics are commonly run to examine the well casing condition due to the known problem of gas well corrosion;
- Information on the amount of money spent annually on corrosion inhibitors, pipe coating, and other preventive measures to mitigate corrosion impacts;
- The fact that well service specialists routinely provide well casing patching, repair, and replacement services,[367] because gas well casing failure is a known problem; and,
- The fact that it is best practice to examine the condition of well casing over the well life to verify its integrity, especially before major well work (e.g. additional drilling, stimulation) is completed on an aging well.[368]

Additionally, Alpha Geoscience criticizes HCLLC for citing industry literature on corrosion best practices, stating that HCLLC's inclusion of this material shows industry bias. HCLLC disagrees with Alpha Geoscience's conclusion. Industry has developed most of the technology to address the problem; therefore, it is logical to cite industry literature on this point.

[365] See Stewart, R.B. and Schouten, F.C. (Shell), Gas Invasion and Migration in Cemented Annuli: Causes and Cures, Society of Petroleum Engineering Paper No. 14779, SPE Drilling Engineering, March 1988. Stewart and Schouten conclude: "*Gas migration resulting from casing contraction is a common field problem… Annular gas-migration problems can develop in an old well owing to changes in pressure or thermal conditions in the well.*"

[366] Alpha Geoscience, Review of the dSGEIS and Identification of Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 18.

[367] Storaune, A., Winters, W.J. (BP America Inc.), Versatile Expandables Technology for Casing Repair, Society of Petroleum Engineers, SPE Paper No. 92330-MS, SPE/IADC Drilling Conference, 23-25 February 2005, Amsterdam, Netherlands, 2005, p.1.

[368] Brondel, D., Edwards, R., Hayman, A., Hill, D., Shreekant, M., Semerad, T., Corrosion in the Oil Industry, Oilfield Review, April 1994, p. 9-10.

Experienced engineers know the importance of assessing and implementing programs to mitigate corrosion/erosion risk early in the field/well lifecycle. Corrosion of gas production equipment is a fundamental concern for the oil and gas industry that has been identified for decades.

> *Failures of equipment handling or producing natural gas occur only in the absence of an adequate corrosion-control program. A successful program is shown to include (1) anticipation of corrosion in design factors of all equipment, (2) detection of corrosion within the system and measurement of its severity for future reference, (3) use of mitigation measures and (4) continual follow-up and adjustment of control techniques. Design factors to be considered are tubing couplings, packers, tubing grade and size, and the number of tubing strings to be set. Future corrosion problems and mitigation work should be recognized at the time the well completion is made so that the best possible design factors can be realized. Corrosion can be detected by gas analysis, water analysis, coupon exposures and caliper surveys. Quantitative data are needed to determine the severity of the problem and to design a suitable program of alleviation of the corrosion. Use of inhibitors and plastic coatings are popular methods for mitigation of corrosion. Both methods have advantages and disadvantages that must be realized and evaluated. Control limits for a mitigation program should be established so that the operator can be certain that he is receiving the desired protection. Gas gathering and* ***process equipment also often suffer from corrosion….***
>
> *It is suggested that an adequate corrosion-control program must include efforts at various levels of company operations. All engineers and supervisors must participate actively in the corrosion-control effort. As a property is being developed, corrosion control should be considered when the equipment to be used is being selected. When development is complete, the operating people must determine the seriousness of their corrosion problems. They must realize that the corrosion attack may change with changes in production characteristics and that absence of corrosion today does not guarantee absence of corrosion tomorrow. When corrosion is detected within an operation, mitigation is in order [emphasis added].*[369]

Because of the known problem of casing corrosion, the National Association of Corrosion Engineers (NACE) developed Recommended Practice RP0186 to mitigate external casing corrosion; this standard applies to the design of cathodic protection for external surfaces of steel well casings, and would be used when soil/subsurface reservoir conditions present a corrosive environment warranting installation of cathodic protection system installation.[370]

NACE International writes:

> *Oil and gas wells represent a large capital investment. It is imperative that corrosion of well casings be controlled to prevent loss of oil and gas, environmental damage, and personnel hazards, and in order to ensure economical depletion of oil and gas reserves necessary [emphasis added].*[371]

[369] Fincher, D.R. (Tidewater Oil Co.), Corrosion in Gas Wells and Gas Gathering Systems, Journal of Petroleum Technology, Volume 13, Number 9, September 1961, Abstract.

[370] NACE International Standard RP0186-2001, Application of Cathodic Protection for External Surfaces of Steel Well Casings.

[371] NACE International, Application of Cathodic Protection for External Surfaces of Steel Well Casings, RP0186-2001, 2001, p.1.

Gas operators stress the importance of corrosion monitoring and control programs. For example, OMV Exploration and Production writes:

> *Corrosion remains a key issue in petroleum production. Its continued occurrence has consequences on the safety of people and environment and the integrity of facilities and affects the economy of the oil or gas field. Particularly the presence of severe environments containing corrosive components such as carbon dioxide and hydrogen sulphide poses serious problems. A central element in the design of facilities and the corrosion control is therefore the proper choice of materials which are both economical and provide a satisfactory performance over the entire service life with respect to the given environment. Prior to the production phase reliable corrosion monitoring programmes have to be selected, established, and implemented, as necessary [emphasis added].*[372]

The magnitude and complexity of a corrosion/erosion mitigation program will vary depending on site-specific conditions. The important step is to complete the initial evaluation, assess the site-specific circumstances, and develop an adequate corrosion/erosion mitigation plan. Some mitigation programs are started early, some are applied intermittently, and others are instituted later in the gas production process; in all cases, an engineering assessment prior to gas drilling and production must be completed to determine the optimal plan.

The corrosion engineering textbook, Corrosion Control in Oil and Gas Production, explains the importance of developing a site-specific plan:

> *The many possible alternatives available today for corrosion management for gas and oil well environments, dictates the need for a thorough evaluation and development of long term plans to assure a safe, economical and effective program. History has shown that both corrosion inhibition and corrosion resistant alloys (CRAs) have been used successfully in tough environments. The final decision on which method to use is often made on the basis of available capital versus long term operating costs [emphasis added].* [373]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantially improved well casing program, including a three-casing-string design. However, this casing is typically made of carbon steel, and must be protected from corrosion and erosion. Chromium steel and corrosion resistant alloys are commonly installed in corrosive environments; however, these metals are substantially more expensive and are not currently proposed for NYS.

Well casing, once installed and cemented into place, will remain in the well for its entire lifecycle, and is often abandoned in place.[374] Therefore, it is in the operator's best economic interest to ensure that its casing investment is protected from corrosion and erosion.

[372] Oberndorfer, M. (OMV Exploration and Production), Corrosion Control in the Oil and Gas Production-5 Successful Case Histories, CORROSION Conference 2007, March 11-15, 2007, Nashville Tennessee, NACE International, 2007, p.1.

[373] Treseder, R.S., Tuttle, R.N., Corrosion Control in Oil and Gas Production, Chapter 14, Corrosion of Steels in Gas Wells, 1998.

[374] In some circumstances corroded casing will be pulled from a well prior to abandonment, although this process can prove difficult, time consuming, and expensive for fully cemented casing strings.

It would be shortsighted for NYS to require a robust well casing program, and not build in a corrosion and erosion control program. Chemicals, metallurgy, monitoring, and repair techniques are available to the operator to manage corrosion and erosion downhole (in the well) and at its surface facilities (e.g. corrosion inhibitors, cathodic protection systems, coatings).

Tools that can be used to monitor well corrosion include caliper tools and casing inspection logs. A caliper tool is run down the inside of the well casing or tubing to measure the internal diameter and assess metal wall loss. Casing inspection logs use ultrasonic and magnetic-flux technology to estimate metal wall loss. Additionally, temperature surveys can be run to look for gas cooling anomalies in the well, which are an indication of casing holes. [375]

NYSDEC has proposed cement evaluation tools to be run when HVHF wells are initially drilled and completed, which is a best practice. Cement integrity should also be monitored periodically over the well's life if casing corrosion occurs. Casing corrosion is an indicator of potential cement deterioration, as explained above.

Without regulations, the decision to invest in corrosion/erosion mitigation and wellbore integrity monitoring is left to the operator. In some cases, operators postpone mitigation to improve early economics. Deferral strategies can produce unfavorable results in the long-term, but may be attractive to small operators that have limited funds, or to large operators that plan to reap the benefits of early production and sell assets soon thereafter. Operators may not implement, unless required, long-term monitoring when faced with declining production, lower profits and when operating cost cuts are sought.

Corrosion and erosion programs that are instituted early can prolong the life of equipment and well casings, and reduce environmental risk. Delayed attention to corrosion and erosion mitigation can result in increased safety, environmental, and human health risks.

Gas well corrosion and erosion can occur in many ways:

- Oxygen contaminated drilling fluids are injected downhole, and can corrode well casing and drilling equipment;
- Water produced along with gas can corrode well casing, tubing, and downhole equipment;
- Acid stimulation treatments, used alone or in conjunction with hydraulic fracturing, readily attack metal;
- Well casing and surface piping can be eroded by high gas production velocities, especially when laden with sediment, sands, or hydraulic fracturing proppants;
- Corrosive soils can cause external corrosion of carbon steel casing;
- Hydrogen sulfide and carbon dioxide, often present in gas production, can corrode carbon steel; and
- Higher wellbore temperatures, increased velocity, and increased salinity accelerate corrosion rates.

NYCRR Proposed Revisions: NYSDEC has not proposed any new requirements for corrosion or erosion mitigation for the Marcellus, Utica, or other low-permeability reservoirs. There are no requirements for corrosion or erosion mitigation or long-term well integrity monitoring in the existing NYCRR.

[375] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

Recommendation No. 99: Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be included in the SGEIS and codified in the NYCRR. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

24. Well Control & Emergency Response Capability

Background: In 2009, HCLLC recommended that NYSDEC require an operator to have an Emergency Response Plan (ERP) and a well blowout control plan. HCLLC recommended that operators be required to demonstrate that they have access to sufficient personnel and resources to respond to a fire, explosion, blowout, or other industrial accident. Best practices include: developing response and well control plans; verifying there are a sufficient number of trained and qualified personnel to carry out the plans; ensuring operators have access to the necessary response equipment; and testing (drills and exercises) the plan prior to drilling.

In 2009, HCLLC also recommended that NYSDEC examine the capacity of local emergency response teams. Oil and gas industry accidents often require highly specialized response capability and equipment. Operators should be required to supplement local emergency response resources to meet this need.

In January 2011, NYS' consultant, Alpha Geoscience, concluded that NYS well control and emergency response planning requirements are narrowly focused on the Bass Island Trend wells. Alpha Geoscience agreed with HCLLC that new regulations are needed for the formations proposed for development under this SGEIS.[376]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a new section (Section 7.13) on Emergency Response Plans, which is a substantial improvement. Section 7.13 states:

> *7.13 Emergency Response Plan*
>
> *There is always a risk that despite all precautions, non-routine incidents may occur during oil and gas exploration and development activities. An Emergency Response Plan (ERP) describes how the operator of the site will respond in emergency situations which may occur at the site. The procedures outlined in the ERP are intended to provide for the protection of lives, property, and natural resources through appropriate advance planning and the use of company and community assets. The Department proposes to require supplementary permit conditions for high-volume hydraulic fracturing that would include a requirement that the operator provide the Department with an ERP consistent with the SGEIS at least 3 days prior to well spud. The ERP would also indicate that the operator or operator's designated representative will be on site during drilling and/or completion operations including hydraulic fracturing, and such person or personnel would have a current well control certification from an accredited training program that is acceptable to the Department [emphasis added].*
>
> *The ERP, at a minimum, would also include the following elements:*
>
> - *Identity of a knowledgeable and qualified individual with the authority to respond to emergency situations and implement the ERP;*
> - *Site name, type, location (include copy of 7 ½ minute USGS map), and operator information;*
> - *Emergency notification and reporting (including a list of emergency contact numbers for the area in which the well site is located; and appropriate Regional*

[376] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 42.

Minerals' Office), equipment, key personnel, first responders, hospitals, and evacuation plan;

- *Identification and evaluation of potential release, fire and explosion hazards;*
- *Description of release, fire, and explosion prevention procedures and equipment;*
- *Implementation plans for shut down, containment and disposal;*
- *Site training, exercises, drills, and meeting logs; and*
- *Security measures, including signage, lighting, fencing and supervision.*[377]

Appendix 6, Proposed Environmental Assessment Form Addendum, requires an Emergency Response Plan be located at the rig, and that the plan be followed. [378]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 2, requires an ERP be provided 3 days prior to spud and available at the site. Condition No. 2 requires the ERP be developed in a manner consistent with the SGEIS, but it does not reference the Chapter 7.13 minimum requirements.

> *An emergency response plan (ERP) consistent with the SGEIS must be prepared by the well operator and be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit. Further, a copy of the ERP in electronic form must be provided to this office at least 3 days prior to well spud.*[379]

The addition of an Emergency Response requirement to the SGEIS is a substantial improvement. However, it is recommended that NYSDEC include a review, approval, and audit process to ensure that quality plans are developed. NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

As proposed by NYSDEC, the operator is required to submit an ERP three days prior to commencing drilling. This leaves no time for regulators to review and approve the ERP. NYSDEC proposes no process for determining the adequacy of the ERP. There is no assessment of personnel training and qualifications, equipment resources, or local emergency response services.

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems.

Larger, paid fire and emergency services departments, located near existing industrial developments, may have some industrial firefighting capability; however, the level of capability should be assessed by the operator and supplemented. If local emergency response services are relied upon in the ERP, operators should ensure emergency response personnel are trained, qualified, and equipped to respond to oil and gas industrial accidents. Small, local, volunteer fire and emergency services departments will typically not be equipped or qualified to meet this need.

[377] 2011 NYSDEC, RDSGEIS, Page 7-146.

[378] 2011 NYSDEC, RDSGEIS, Appendix 6, Page A6-7.

[379] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 1 of 17.

Recommendation No. 100: NYSDEC should identify an Emergency Response Plan (ERP) review, approval, and audit process to ensure that quality plans are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells.[380] This risk statistic is applicable to Marcellus and other low-permeability gas reservoir drilling that is still in the exploration and appraisal phase in NYS. Blowout rates are less frequent for production wells where more information is known about the reservoir, well control is optimized, and personnel are more experienced in site-specific conditions. For example, a review of production well blowouts in California estimated 1 blowout per 2,500 wells drilled. [381] California's data showed that: 25% of the blowouts affected more than 25 acres; the average blowout lasted 18 hours; and the maximum blowout length was 6 months.

Using the California statistic of 1 blowout per 2,500 production wells drilled (which is more conservative than the exploration well statistic of 7 blowouts per 1,000 exploration wells), and NYS' estimate of 1600 wells per year over 30 years, an incremental likelihood of 19 blowouts is estimated for NYS.[382] Because some of the early wells drilled will be exploration wells, the blowout frequency many be higher in the first few years of shale gas development in NYS and it is plausible that 40[383] or more well blowouts could occur during the next 30 years. Therefore, blowouts are a reasonably foreseeable significant impact, and mitigation is warranted.

Hydrocarbon reservoirs can contain large quantities of gas and formation water, which can be released into the surrounding environment during a well blowout, resulting in significant damage. For example, the Chesapeake Energy 2011 Marcellus well blowout in Bradford County, Pennsylvania spilled thousands of gallons of fracture treatment fluid over "containment walls, through fields, personal property and farms, even where cattle continue[d] to graze."[384]

Methods to control a gas well blowout can require significant water withdrawals – from 500,000 to 6,000,000 gallons per day. Well control experts may also use foam and dry chemicals to respond to a blowout. Controlling a well blowout can create large volumes of waste. Rig-deluge operations create large pools of water that can transport oil, chemicals, fuels, and other materials toward lower elevation drainage areas.

In addition to the Chesapeake Energy 2011 well blowout, another Pennsylvania Marcellus Shale blowout occurred in 2010.[385,386] Also, in 2010, there was a major industrial fire. The 2010 incidents prompted

[380] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[381] Jordan, P.D., and Benson, S. M., Well Blowout Rates in California Oil and Gas District 4- Update and Trends, Summary of Well Blowout Risks for California Oil and Gas District 4, 1991-2005, Table 1

[382] 19 blowouts= (1,600 wells drilled per year)(30 years)(1 blowout per 2500 wells drilled).

[383] 40 blowouts= 1,600 wells drilled per year)(2 years)(7 blowout per 1000 wells drilled)+(1,600 wells drilled per year)(28 years)(1 blowout per 2500 wells drilled).

[384] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[385] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

Pennsylvania to realize the need for its own emergency response services, with trained and qualified personnel and adequate equipment available 24 hours per day, 7 days per week. The news reported that it took "16 hours for out-of-state crews to address a June 3 blowout in Clearfield County and 11 hours to extinguish a July 23 fire in Allegheny County. In both cases, well operators had to wait for response crews to fly in from Texas."[387]

In 2010, CUDD Well Control located a new facility in Canton Township, Bradford County, Pennsylvania. Canton Township is located near the southern NYS border. It may be possible for NYS operators to contract with CUDD to provide emergency response services. However, a better alternative may be for NYS to collaborate with a well control specialist to provide more centrally located services dedicated to supporting NYS' proposed drilling activity.

The 2011 RDSGEIS requires operators to develop and implement a blowout preventer (BOP) testing program. However, the SGEIS does not unequivocally require a well control expert be on contract. It is recommended that NYSDEC require operators to have a contract in place for immediate response by a trained and qualified well control contractor. If a contract with a well control expert is not in place when a blowout occurs, contract negotiations can cause detrimental delays.

Well capping is a proven, effective, and rapid method to control a blowout. Well control contractors provide the expertise and equipment for this operation. However, in some limited cases, well capping is not effective, and a relief well may be required. Therefore, it is important for operators to also have prearranged access to a relief well rig, either via a contract with a rig provider or via a memorandum of agreement to provide emergency response assistance with a nearby operator.

> Recommendation No. 101: NYSDEC should require a well blowout response plan (either included in the Emergency Response Plan or as a separate plan), a contract retainer with an emergency well control expert, and prearranged access to a relief well rig.

NYCRR Proposed Revisions: NYSDEC has proposed a new regulation at 6 NYCRR § 560.5 requiring an ERP for HVHF wells. This is a substantial improvement; however, this plan should be required for all wells in NYS, not just HVHF wells. Additionally, the NYCRR should more clearly specify the ERP content requirements and include the recommendations listed above.

> Recommendation No. 102: The requirement for an Emergency Response Plan should be codified in the NYCRR. It should apply to all wells in NYS, not just HVHF wells. The NYCRR should specify ERP content requirements. These requirements should be consistent with NYSDEC's recommendations listed in Chapter 7.13 of the 2011 RDSGEIS.

[386] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[387] http://pagasdrilling.com/tag/cudd-well-control/

25. Financial Assurance Amount

Background: In December 15, 2008, scoping comments to NYSDEC, NRDC, and its co-signatories requested the DSGEIS examine whether NYSDEC requires a sufficient financial assurance amount (in the form of a bond or other financial instrument). In its comments on the 2009 DSGEIS, NRDC and its co-signatories, as well as HCLLC, noted that the DSGEIS did not provide an analysis of the current financial assurance requirements, and requested that work be done.

HCLLC recommended that the SGEIS examine financial assurance amounts to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination).

Long horizontal wells are more costly to plug and abandon than vertical wells. Also, surface impacts are increased when high-volume fracture stimulation treatments are employed and multiple wells are drilled from a single well pad. Both of these operations require additional gas treatment and transportation facilities.

In January 2011, NYS' consultant, Alpha Geoscience, advised NYSDEC to ignore financial assurance recommendations, declaring it "out of scope" of the SGEIS, because legislative action would be required at ECL 23-0305(8)(k).[388] HCLCC disagrees. Regardless of whether a legislative change is required, financial assurance improvements for Marcellus Shale gas well drilling should not be disregarded in the RDSGEIS; instead, the SGEIS should recommend to NYS' Legislature the need for legislative action as a mitigating measure.

The 2011 RDSGEIS: The 2011 RDSGEIS still does not include recommendations for increasing the financial assurance amounts for HVHF shale gas operations.

NYCRR Proposed Revisions: There is no proposed revision to the amount of financial security for wells up to 6,000' deep. 6 NYCRR § 551.5. For wells between 2,500' and 6,000' in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000.

For wells drilled more than 6,000' deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6).

In 2003, ICF completed a report for the New York State Energy Research and Development Authority (NYSERDA) on NYS oil and gas wells.[389] ICF's report advised NYS that well plugging and abandonment can range from $5,000 per well to more than $50,000 per well depending on the well depth, well condition, site access, and site condition.[390] ICF's 2003 report recommended that NYS consider increased financial security requirements. NYSDEC's current requirement of only $5,000 financial

[388] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 46.

[389] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003. This report is found at http://esogis.nysm.nysed.gov/esogisdata/downloads/NYSERDA/7012.pdf. The report is listed as a draft, and a final could not be located on the world-wide web.

[390] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page. ES-1.

security per well is clearly insufficient, if ICF determined in 2003 that the cost could be as much as $50,000 per well. Today's cost would likely be higher, almost a decade later.

In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas. The Ohio Code at Title 15, Chapter 1509 requires:

> *1509.07 Liability insurance coverage. An owner of any well, except an exempt Mississippian well or an exempt domestic well, shall obtain liability insurance coverage from a company authorized to do business in this state in an amount of not less than one million dollars bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the drilling, operation, or* ***plugging of all the owner's wells in this state.*** *However, if any well is located within an urbanized area, the owner shall obtain liability insurance coverage in an amount of not less than three million dollars for bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the* ***drilling, operation, or plugging of all of the owner's wells in this state****. The owner shall maintain the coverage until all the owner's wells are plugged and abandoned or are transferred to an owner who has obtained insurance as required under this section and who is not under a notice of material and substantial violation or under a suspension order. The owner shall provide proof of liability insurance coverage to the chief of the division of oil and gas resources management upon request. Upon failure of the owner to provide that proof when requested, the chief may order the suspension of any outstanding permits and operations of the owner until the owner provides proof of the required insurance coverage.[emphasis added]*
>
> *Except as otherwise provided in this section, an owner of any well, before being issued a permit under section 1509.06 of the Revised Code or before operating or producing from a well, shall execute and file with the division of oil and gas resources management a surety bond conditioned on compliance with the restoration requirements of section 1509.072, the plugging requirements of section 1509.12, the permit provisions of section 1509.13 of the Revised Code, and all rules and orders of the chief relating thereto, in an amount set by rule of the chief.*

Recommendation No. 103: NYSDEC's financial assurance requirements should not narrowly focus on the cost for plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be included in the SGEIS as a mitigating measure, even if legislative action is ultimately required. Additionally, improved financial assurance should be codified in the NYCRR during this revision to the extent possible.

By comparison, Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well.[391] Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS.

[391] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

In addition to the bond amount, Fort Worth, Texas also requires the operator to carry multiple insurance policies:

1. *Standard Commercial General Liability Policy of at least $1,000,000 per occurrence. The Standard Commercial General Liability insurance must include: "premises, operations, blowout or explosion, products, completed operations, sudden and accidental pollution, blanket contractual liability, underground resources and equipment hazard damage, broad form property damage, independent contractors' protective liability and personal injury."*
2. *Excess or Umbrella Liability of $5,000,000;*
3. *Environmental Pollution Liability Coverage of at least $5,000,000 "applicable to bodily injury, property damage, including the loss of use of damaged property or of property that has not been physically injured or destroyed; cleanup costs; and defense, including costs and expenses incurred in the investigation, defense or settlement of claims…coverage shall apply to sudden and accidental, as well as gradual pollution conditions resulting from the escape or release of smoke, vapors, fumes, acids, alkalis, toxic chemicals, liquids or gases, waste material or other irritants, contaminants or pollutants."*
4. *Control of Well Policy of at least $5,000,000 per occurrence/combined single limit with a $500,000 sub-limit endorsement for damage to property for which the Operator has care, custody and control; and*
5. *Other insurance required by Texas (e.g. Workers Compensation Insurance, Auto Insurance, and other corporate insurance required to do business in the state of Texas).*[392]

Financial assurance requirements should be increased to address worst-case risk exposure. Risk assessments should include worst-case scenario financial impact models. The risk modeling should be used to set higher financial assurance requirements.

Recommendation No. 104: The financial assurance requirements at 6 NYCRR §§ 551.5 and 551.6 are insufficient to address the risks to NYS and private parties associated with oil and gas development. It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment.

[392] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

26. Seismic Data Collection

Background: In 2009, HCLLC recommended that NYSDEC improve the DSGEIS and establish regulatory requirements for seismic data collection to reduce impacts to the environment and the public. The 2009 DSGEIS addressed naturally occurring seismic events in Chapter 4, but was silent on the impacts from industrial seismic exploration, which is used to locate subsurface gas reservoirs including shale gas targets.

This problem persists in the 2011 RDSGEIS. The 2011 RDSGEIS discusses naturally occurring seismic events, and seismically induced fractures from HVHF operations, but does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys used to target hydrocarbon formations for exploration and appraisal drilling. These seismic surveys are also useful to identify major fault systems to be used in HVHF design and modeling. Improved understanding of the subsurface stratigraphy and fault systems will improved 3D model simulation predictions and can aid engineers in designing HVHF treatments that do not link induced fractures with existing, conductive, natural fault systems that could move HF fluids into protected groundwater resources or water wells.

In January 2011, NYS' consultant, Alpha Geoscience provided a misguided recommendation to NYSDEC to ignore seismic data collection mitigation in the RDSGEIS, as "irrelevant."[393] Because seismic data collection is typically the first step in unexplored areas, to locate and optimize exploration drilling targets, seismic data collection mitigation when used to target Marcellus Shale wells is hardly "irrelevant."

Therefore, it is unclear whether NYSDEC is not familiar with the use of seismic data collection to target hydrocarbon formations for drilling, and the mitigation measures needed because its consultants advised against study of this important mitigation, or whether shale gas operators have told NYSDEC that they don't intend to collect two-dimensional (2D) or three-dimensional (3D) seismic surveys prior to exploring in the Marcellus Shale.

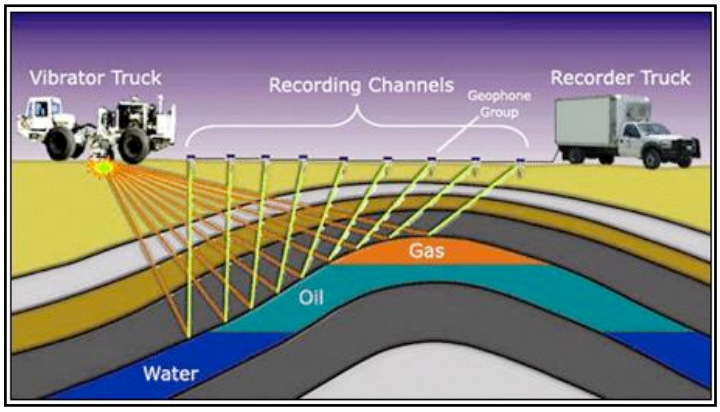
If operators do not intend to collect additional 2D and 3D data, that representation should be stated in the RDSGEIS, and the 2D and 3D data collection should be precluded in NYS. Otherwise, the impacts of this work should be identified and mitigated. This is an important issue to resolve, because seismic surveys can create significant surface impacts and disruptions.

> Recommendation No. 105: If 2D or 3D seismic surveys are planned, or are possible in the future, the NYCRR should codify a permitting process for these activities and institute mitigating measures in the SGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas.

Exploration for oil and natural gas typically begins with a geologic examination of the surface structure of the earth, to identify areas where petroleum or gas deposits might exist. Once a geologist/geophysicist has identified an area of potential interest based on surface geologic maps, seismic data collection is typically obtained to identify possible subsurface hydrocarbon traps and structures.

[393] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011.

Seismic exploration equipment is used to send seismic waves into the earth. Seismic waves are generated by a surface positioned source and are measured by a surface positioned receiver. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Collecting seismic data in this manner is called a Reflection Seismic Survey.[394]





A reflection seismic survey involves generating hundreds to tens of thousands of seismic source events, or shots, at various locations in the survey area. The seismic energy generated by each shot is detected and recorded by sensitive receivers ("geophones" on land and "hydrophones" under water) at a variety of distances from the source location. Geophones and hydrophones are connected by long cables to relay the collected information back to a centralized computer. The photo to the left is a geophone and cable system.[395]

For every source event, each geophone generates a seismogram or trace, which is a time series representing the earth movement at the receiver location. A record of all traces for each shot is transmitted to a computer for storage and conversion into a seamless cross-sectional representation of the subsurface for subsequent study and interpretation by a trained geophysicist.

Onland seismic operations involve generation of seismic vibrations by explosive energy sources or by mechanical sources. One type of energy source for seismic exploration is an explosive charge. Small holes ("shot-holes"), typically 4 inches in diameter are drilled into the earth surface, 10-60' deep depending on surface terrain.[396] Although, some drill holes have been drilled to 200'.[397] The photo to the right shows an example of a shot-hole drill unit.



[394] U.S. Geologic Survey, Seismic Data Acquisition.

[395] Geophone and cable photo from http://www.anr.state.vt.us/dec/geo/newbedu.htm, State of Vermont.

[396] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

[397] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

The hole must be drilled into a hard layer of soil that is sufficiently dense to carry the seismic wave.[398] Explosive charges (typically 5-50 pounds each)[399] are lowered into the hole and detonated to create a shock wave (vibration). Some states have limits on the size of charges that can be deployed near environmentally sensitive areas, human inhabitation and near roadways.

Historic use of explosives on the ground surface resulted in large craters and extensive surface damage. Explosive charges are no longer deployed at the surface. Instead, a shot-hole must be drilled and the explosive lowered into the shot-hole at a sufficient depth to prevent surface craters. Shot-holes are filled with cuttings, bentonite and rocks to minimize surface impact.

Mechanical vibrators are an alternative to the use of explosives, and are more commonly used. Mechanical vibrators provide more consistent source strength and repeatability, and they are more reliable in the case of repeat data acquisition programs or for time-lapse studies.

Mechanical vibrators can include: a pad that thumps the surface of the earth ("thumper trucks"), driven by gravity or compressed air; a truck that generates vibrations ("Vibroseis™ Truck"); and compressed air guns.[400] The photo to the right shows a Vibroseis Truck. The Vibroseis method involves a truck equipped with vibrator pads that are lowered to the ground and triggered. Depending on the subsurface target depth and the purpose of the seismic survey, two or more seismic Vibroseis Trucks (vibrating in sync) may be needed.



In cold climates, ice road construction and use of Vibroseis Trucks for seismic data acquisition is the norm. Seismic data is typically secured over the winter months along ice road routes, to reduce footprint and stress to sensitive areas of the tundra environment.



The use of thumper trucks is not considered best practice because it involves dropping a steel slab that weighs about three tons to the ground to create a seismic vibration. Thumper trucks are large, requiring extensive tree and vegetation removal, and leave land scars.

In areas where seismic data is collected in water, the energy source is usually compressed air in an airgun submerged underwater, because explosives can cause adverse impacts to aquatic life.

[398] The Pembina Institute, Seismic Exploration, www.pembina.org.

[399] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

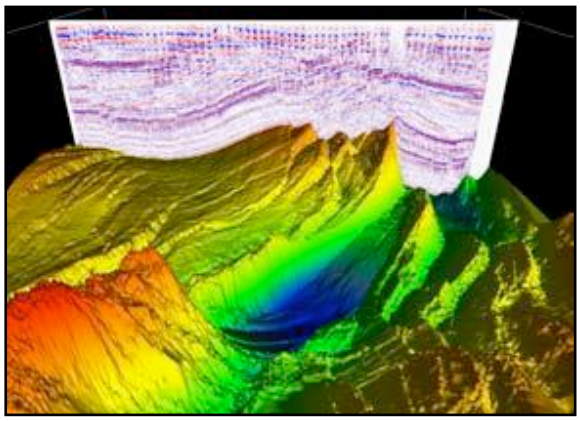
[400] Petroleum Engineering Handbook, Reservoir Engineering and Petrophysics, Volume V(A), Society of Petroleum Engineers, 2007.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (as shown in the photo to the left). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection. The width of each cutline depends on the seismic survey method used, but can be on the order of 20'-50' wide where large seismic equipment units are required. Best practice is to decrease the width of the cutlines to as small as possible using hand carried equipment. More recently companies have been able to reduce cutline width to 6'-10' in certain circumstances.

The spacing between each cutline is dependent on the type of seismic equipment used and depth of examination into the earth. The distance between each cutline is typically 300' apart (shallow reservoir targets) to 3,000' apart (deeper reservoir targets).[401]

Depending on existing development, infrastructure and access in the area planned for onshore seismic exploration, a seismic operator may need to build access roads, set up temporary camps and establish helicopter landings to bring in personnel and equipment. In areas where there are existing roads, housing and airports, surface disturbance can be minimized.

A basic set of seismic data can be obtained by setting a two dimensional array of seismic sources and receivers (2D seismic). Typically 2D seismic requires seismic lines tens of miles apart. Often 2D data is acquired along existing roads or access routes to minimize surface impacts. Along the 2D seismic cutlines shot-points and receivers are evenly spaced to send and receive a signal. This process produces a 2D slice of the subsurface.



If funding is available, operators generally opt to collect three dimensional seismic (3D seismic) images of the subsurface. 3D seismic data acquisition involves a much more intensive data collection effort, using multiple shot lines arranged perpendicular to multiple receiver lines of geophones, with seismic lines spaced several hundred feet apart, rather than miles apart.[402] An example of a map produced from a 3D seismic survey is shown to the left.

Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions. None of these impacts have been analyzed in the NYS RDSGEIS.

There are typically six different crews deployed: (1) access crews, that clear seismic lines, (2) "shooters" that drill the shot-holes and set the explosive charges or run the mechanical vibration equipment to generate seismic waves, (3) "recorders" that set the geophones and measure the seismic reflection, (4) the "pick-up" crews that move the equipment from one location to the next along the seismic lines,

[401] The Pembina Institute, Seismic Exploration, www.pembina.org.

[402] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

(5) logistical support crews that provide housing, food, medical, maintenance and repair, and transportation; and (6) remediation and plugging crews that restore the area and plug shot-holes (if used).

> Recommendation No. 106: The increased industrial activity (e.g. economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the SGEIS.

In 2011, HCLLC developed a report for NRDC and Sierra Club describing the types of impacts that occur from 2D and 3D seismic surveys, and made recommendations for best practices and model permit requirements. The recommendations in this report could be considered by NYSDEC in crafting seismic survey requirements for NYCRR.[403]

> Recommendation No. 107: Consider the best practices and model permit requirements proposed in Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011, for inclusion as mitigation measures in the SGEIS and improvements in the NYCRR to regulate seismic survey data collection.

[403] Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011.

APPENDIX A

Surface Casing Table

Appendix A - Surface Casing Table

Surface Casing Requirement	2011 RDSGEIS Appendix 8 Casing and Cementing Practices	2011 RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	2011 RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed Permit Conditions and Recommendations in 2011 RDSGEIS	NYCRR Requirements for all Wells, NYCRR Part 554	ADDITIONAL NYCRR Requirements for all HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Setting Depth	75' beyond the deepest fresh water zone encountered or 75' into competent rock (bedrock), whichever is deeper.	100’ below the deepest freshwater zone and at least 100’ into bedrock.	No requirement listed; assume it defaults to the Appendix 8 requirement of 75'.	The Appendix 10 HVHF surface casing setting depth requirement is less stringent than the Appendix 9 requirement; both should be 100'. NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether the setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths.	Surface casing must be run in all wells to extend below the deepest potable fresh water level. Neither the 75' nor the 100' setting depth below the deepest protected water zone is specified in the NYCRR.	No additional requirement.	NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.
Protected water depth estimate and verification	No requirement.	Estimated in drilling application and verified while drilling.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.
Cement Sheath Width	No requirement.	At least 1-1/4".	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Appendix A - Surface Casing Table

Surface Casing Requirement	2011 RDSGEIS Appendix 8 Casing and Cementing Practices	2011 RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	2011 RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed Permit Conditions and Recommendations in 2011 RDSGEIS	NYCRR Requirements for all Wells, NYCRR Part 554	ADDITIONAL NYCRR Requirements for all HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Amount of Cement in Annulus	Not specified, but it is presumed that the goal is to complete annulus cementing, because the requirements include 25% excess cement; however, the conditions require a reporting of the cement top location, if cement is not returned to the surface, which indicates that NYSDEC could accept a partially cemented annulus.	Entire annulus must be cemented; cement squeeze may be required.	No requirement listed; assume it defaults to Appendix 8 requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus.	There is a requirement to circulate cement to the top of the hole.	No additional requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.
Shallow gas hazards	Surface hole drilling must stop and surface casing must be set and cemented before drilling deeper into hydrocarbon resources.	The likelihood of shallow gas hazards must be estimated in the drilling application and verified while drilling.	No requirement listed; assume it defaults to Appendix 8 requirement.	All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. If a shallow gas hazard is encountered, surface casing should be set and cemented to protect water resources, before drilling deeper into hydrocarbon resources.	No requirement.	No requirement.	If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.
Excess Cement Requirement	25%	50%	No requirement listed; assume it defaults to Appendix 8 requirement of 25%.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume.	No requirement.	No requirement.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

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Cement Type	The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content and contain a gas-block additive.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.
Lost Circulation Control	Required.	Required.	Required.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

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Spacer Fluids	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	Required.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Hole conditioning before cementing	Gas flows must be killed or lost circulation must be controlled and the hole be conditioned before cementing.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	At least every 120', with a minimum of two centralizers. A table of centralizer-hole size combinations is included.	At least every 120'.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

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Surface Casing Requirement	2011 RDSGEIS Appendix 8 Casing and Cementing Practices	2011 RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	2011 RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed Permit Conditions and Recommendations in 2011 RDSGEIS	NYCRR Requirements for all Wells, NYCRR Part 554	ADDITIONAL NYCRR Requirements for all HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing quality	All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi); used casing may be approved for use, but must be pressure tested before drilling out the casing shoe.	New pipe with minimum internal yield pressure (MIYP) of 1,800 psi, or reconditioned pipe that has been tested internally to a minimum of 2,700 psi, must be used.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.	No requirement.	All casing must be new and conform to the industry standards specified in the permit to drill.	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.	No requirement.	Casing thread compound and its use must conform to the industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

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Drilling Mud	No requirement.	Compressed air or WBM, no SMB or OBM.	Not listed in Appendix 10, but the RDSGEIS text includes a section that states compressed air or WBM should be used on HVHF wells.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells, not just those described in Appendix 9.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.
Cement Setting Time	Compressive strength standard of 500 psi.	No requirement listed; assume it defaults to Appendix 8 requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.
NYSDEC Inspector	No requirement.	Required to be onsite for cementing operations.	No requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation.	No requirement.	No additional requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

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Cement QA/QC - Cement Evaluation Log	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	No requirement listed; assume it defaults to Appendix 8 requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.	No requirement.	No additional requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.
Formation Integrity Test	No requirement.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

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BOP Installation	Confirmation that the surface casing is set and cemented into place, such that the BOP can be secured and effective when drilling deeper into the well.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP.	No requirement.	No requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	Not specified.	Not specified.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the Department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

APPENDIX B

Intermediate Casing Table

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Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Waiver Provision to Exclude Use of Intermediate Casing	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.	No requirement.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.
Setting Depth	No requirement.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.
Protected Water Depth Estimate and Verification	No requirement.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.
Amount of Cement in Annulus	No requirement.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.
Excess Cement Requirement	No requirement.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

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Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	No requirement.	No requirement.	Cement slurry must be prepared to minimize its free water content, in accordance with industry standards and specifications.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used , not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

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Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	No requirement.	No requirement.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers, must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.
Casing quality	No requirement.	No requirement.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Drilling Mud	No requirement.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.
Cement Setting Time	No requirement.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

Appendix B - Intermediate Casing Table

Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
NYSDEC Inspector	No requirement.	No requirement.	Required to be onsite for cementing operations.	Best practice is to have a state inspector onsite during cementing operations.	No requirement.	No requirement.	Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	No requirement.	No requirement.	No requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	No additional requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

APPENDIX C

Production Casing Table

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Design	No requirement.	No requirement.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.	The drilling, casing and completion program adopted for any well shall be such as to prevent the migration of oil, gas or other fluids from one pool or stratum to another.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No additional requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where production casing is set.
Amount of Cement in Annulus	The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.	No additional requirement. Appendix 8 requirement would apply.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice.	If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Excess Cement Requirement	A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	No additional requirement.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.
Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	No additional requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No additional requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement Installation and Pump Rate	The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.	No additional requirement. Appendix 8 requirement would apply.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. The pump and plug installation method is a best practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will be come more difficult with a deviated wellbore, but should be attempted if achievable.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.
Centralizers	Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval.	No additional requirement. Appendix 8 requirement would apply.	At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002)	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.
Casing quality	The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.	No additional requirement. Appendix 8 requirement would apply.	Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited.	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Cement Setting Time	Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way.	No additional requirement. Appendix 8 requirement would apply.	After the cement is pumped, the operator must wait on cement (WOC): 1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psi, and 2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test.	Operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.
NYSDEC Inspector	No requirement.	No requirement.	This office must be notified _____ hours prior to production casing cementing operations.	Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.	No requirement.	No additional requirement.	Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 “Other Testing and Information” under the heading of “Well Logging and Other Testing” of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009).	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the production casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.
Record keeping	No requirement.	No requirement.	A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Additional Casing or Repair	No requirement.	No requirement.	Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Appendix D: List of Acronyms

^{210}Po .....Polonium 210
2D.....two-dimensional
3D.....three-dimensional
API.....American Petroleum Institute
API RP .....American Petroleum Institute Recommended Practice
AQ.....Air Quality
AMD .....Acid mine discharge
ARD .....Acid Rock Drainage
Bcf.....billion cubic feet
BOP.....Blow-out preventer
BTEX .....benzene, toluene, ethylbenzene, and xylenes
BUD .....Beneficial Use Determination
C-NLOPB .....Canada-Newfoundland and Labrador Offshore Petroleum Board
CDA .....Concentrated Development Area
CRI.....Cuttings reinjection technology
CRA .....Corrosion-resistant alloys
CRDPF.....Continuously Regenerating Diesel Particulate Filters
DOI .....United States Department of the Interior
DMM .....Division of Materials Management
EAF.....Environmental Assessment Form
EPA.....Environmental Protection Agency
ERP .....Emergency Response Plan
GHG.....Greenhouse Gases
H2S .....Hydrogen Sulfide
HAP .....Hazardous Air Pollutants
HVHF.....High Volume Hydraulic Fracturing
JPAD.....Jonah-Pinedale Anticline Development Area
LDAR.....Leak Detection and Repair
MACT.....Maximum Achievable Control Technology
MFN.....Microseismic Fracture Network
MMscf.....Million standard cubic feet
MSDS.....Material Safety Data Sheet
MSW.....Municipal solid waste
NAAQS.....National Ambient Air Quality Standards
NACE.....National Association of Corrosion Engineers
NO_X.....Nitrogen Oxide
NORM .....Naturally Occurring Radioactive Material
NRDC .....Natural Resources Defense Council
NYCRR.....New York Code of Rules and Regulations
NYS .....New York State
NYSDEC .....New York State Department of Environmental Conservation
NYSERDA.....New York State Energy Research and Development Authority
NYSDOH.....New York State Department of Health
OBM .....Oil-Based Mud
OSHA.....Occupational Safety and Health Administration
OSPAR.....Oslo-Paris Convention

P&A .....Plug & Abandonment
PA .....Pennsylvania
PADEP.....Pennsylvania Department of Environmental Protection
PLONOR .....Pose Little Or No Risk
$PM_{2.5}$.....Particulate Matter, 2.5 microns or smaller in diameter
POTW .....Publically Owned Treatment Works
ppm .....parts per million
psi.....pounds per square inch
QC/QA .....Quality Control/Quality Assurance
Ra .....Radium
RDSGEIS.....Revised Draft Supplemental Generic Environmental Impact Statement
REC.....Reduced Emission Completions
RP.....Recommended Practice
RCRA.....Resource Conservation and Recovery Act
SBM .....Synthetic-Based Muds
SCR.....Selective Catalytic Reduction
SDWA.....Safe Drinking Water Act
SEQRA .....State Environmental Quality Review Act
SPDES .....State Pollutant Discharge Elimination System
SO_2 .....Sulfur Dioxide
SPCC.....Spill Prevention Control and Countermeasures
SPOTS .....Spill Prevention Operations Technology Series
SRB.....Sulfate-reducing bacteria
STEL.....Short-term exposure limit
STI .....Steel Tank Institute
SWPPP.....Storm Water Pollution Prevention Plan
TDS.....Total Dissolved Solids
TEG.....Triethylene Glycol
TENORM.....Technologically Enhanced Naturally Occurring Radioactive Material
TVD .....True Vertical Depth
USDW.....Underground Sources of Drinking Water
USEPA.....United States Environmental Protection Agency
USGS .....United States Geological Survey
VOC.....Volatile Organic Compound
WBM .....Water-based muds
WOC .....Wait on Concrete

Attachment 2

Tom Myers, Ph. D.

Technical Memorandum

Review and Analysis

Revised Draft

Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

September 2011

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INTRODUCTION

This technical memorandum reviews aspects of the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) on the *Oil, Gas and Solution Mining Regulatory Program regarding Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoir*. The New York State Department of Environmental Conservation (NYSDEC) is the lead agency. Throughout this review, I refer to the document as the RDSGEIS. The document was "revised" since its initial publication in 2009. I had prepared a review of the 2009 DSGEIS as Myers (2009).

Appendix A to this technical memorandum is my specific review of Appendix 11 in the RDSGEIS, which has been excerpted from the 2009 DSGEIS without change. Appendix B to this technical memorandum is a paper I wrote which is currently undergoing peer review for a journal; this paper concerns vertical transport of contaminants from the shale to freshwater groundwater.

Since the 2009 DSGEIS, the New York State Energy Research and Development Authority (NYSERDA) contracted with Alpha Geoscience (Alpha) to review the comments I prepared on the 2009 DSGEIS (Myers, 2009). Alpha produced a report titled: *Review of dSGEIS and Identification of Best Technology and Best Practices Recommendations, Tom Myers: December 28, 2009*, prepared by Alpha. The RDSGEIS does not reference, or apparently rely, on this Alpha review in any meaningful way; the bibliography includes a list of 2011 reports by Alpha, but the apparent reference to this review (Alpha 2011) does not include my name. The consultants bibliography includes a subheading with Alpha's report, with "Myers" misspelled, but no apparent use of this reference either. Alpha's reviews prepared for NYSERDA were not available directly on the RDSGEIS web page other than through an obscure link. Appendix C to this technical memorandum is my response to Alpha (2011).

This technical memorandum also reviews the water resources/hydrogeology aspects of the revised regulations, published as *Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560, Subchapter B: Mineral Resources*, referred to throughout as the proposed regulations. This technical memorandum proposes additional regulations throughout the review, and then includes a separate section regarding specific proposed regulations.

The report focuses on three main aspects of the RDSGEIS: (1) hydrogeology, including the hydraulic fracturing (fracking) process, (2) low flow surface water resources, and (3) water-resource-related setbacks. Hydrogeology includes review of the geology, contaminant transport, shale hydrogeology, groundwater quality, and induced seismicity analyses. Low flow

surface water resources include an assessment of the analysis required to determine passby flows and the requirements/restrictions on pumping from aquifers. Consideration of the proposed setbacks includes whether the proposed setback is based on facts or analysis. Specific setbacks considered include those proposed to protect aquifers, wells, springs, and other water-related resources.

The RDSGEIS provides data and analysis almost exclusive to the Marcellus shale, although the regulations purport to govern all low-permeability formations, including the Utica shale (which is mentioned in the RDSGEIS). Developing different low-permeability formations would have different effects than would development of the Marcellus shale, which is the focus of the RDSGEIS. Deeper shale, such as the Utica shale, would generate far more cuttings and use more drilling mud, which present different disposal issues. The amount of water used for fracking could be different, as well. Development of shallower shales would increase the regional hydrogeology impacts and increase the potential vertical contaminant transport and the prevalence of improperly plugged abandoned wells. Additionally, the RDSGEIS focused its analysis from the total amount of surface water withdrawals to wastewater disposal on the wells expected in the Marcellus shale. Additional shale development would vastly increase the impacts beyond those revealed in this RDSGEIS

- *The RDSGEIS and proposed regulations should acknowledge that they apply only to the Marcellus shale.*
- *Additional low-permeability gas plays require additional supplemental GEIS analyses as suggested in RDSGEIS 3.2.1*.

The focus on this review is on development of the Marcellus shale, because except for Chapter 4, the RDSGEIS discussion is limited to the Marcellus shale.

SUMMARY OF FINDINGS

The RDSGEIS only poorly describes the hydrogeology of the Marcellus shale area and of the shale in particular. It does not provide a description of what fracking does to the shale or how it affects the regional hydrogeology. There is no description provided of the geologic formations between the shale and the surface beyond the general stratigraphy and stating that it would be nonconductive to upward flow, a point not supported with data or by the literature. The fault mapping is outdated.

Industry should be required to complete geophysical logging, including conductivity, to determine the lower extent of freshwater (Williams 2010). The definition of freshwater should

be as protective as federal standards, meaning that surface casing should extend to TDS at 10,000 ppm.

The description of fracking is incomplete and incorrect from a hydrogeologic perspective. The contention that out of formation fracking is rare is incorrect based on industry data which has documented fractures as much as 2000 feet above the top of the shale in other states. Also, the contention that fracking pressure dissipates immediately upon cessation of injection is also incorrect, except right at the well. Model simulations show that pressure in the shale remains elevated for more than three months and that that prevents some of the injected fluid from flowing back to the gas well. The injected fluid displaces substantial amounts of formation fluid from the shale into surrounding formations; existing and new fractures allows that fluid to move much further from the shale than expected due simply to the volume injected.

The RDSGEIS dismisses the concept of contaminant transport from the shale to the near-surface aquifers, but there is overwhelming evidence that it is at least possible. Fracking fluids and methane have been found in water wells from fracking in different areas. Simulations indicate it could occur much more in the future. Fracking displaces large quantities of brine, and fractures provide pathways to the surface; fracking may also widen those existing pathways. Areas of natural artesian pressure would allow advection to move fluids and contaminants vertically upward. Mapping areas of artesian pressure, improved regional fault mapping, and site-specific project by project fault mapping should be employed to avoid areas of enhanced vertical transport potential. Long-term multilevel monitoring is also needed to track the future potential of vertical contaminant movement.

NYSDEC proposes setbacks that are not obviously based on observed data. If the setback from fracking in a protected watershed is 4000 feet, the setback from primary or principal aquifers or from public water supply wells should be no less, unless justified by site-specific analyses. Wells located in a 100-year floodplain have a greater than 1 in 4 chance of being flooded in a 30-year project life, therefore wells should be setback further from streams.

The proposed monitoring plans are paltry and insufficient. Simply monitoring existing water wells only shows when that user is affected, it does not protect the aquifer. Water wells are not designed for monitoring. The industry should establish a dedicated groundwater monitoring system downgradient from every well pad, out to at least the distance that a contaminant would travel in five years. Monitoring should continue for at least five years after the cessation of production.

The required passby flows have improved since 2009, as has the method for determining them. In general requiring the Q60 and Q75 monthly flow avoids diversions at all when flows are in the bottom 40 or 25 percent of their normal monthly flow regime, depending on area and

month. Q75 only applies to larger streams (> 50 square mile watershed) during the winter months when flow is generally higher. The RDSGEIS should provide some data to show the estimation methods for ungaged sites is accurate.

HYDROGEOLOGY

This section considers all aspects of the RDSGEIS that concern underground resources, including aspects of geology, shale hydrogeology, contaminant transport, the descriptions of fracking and the potential for fracking-induced seismicity. The toxicity of fracking fluid additives was considered was considered by Dr. Glenn Miller.

General Hydrogeology

The distinction between primary and principal aquifers and other sources (RDSGEIS, p. 2-20) ignores the connections between surface and groundwater. Groundwater from principal aquifers may seep into streams, especially during periods of low flow. Because those aquifers are also used by New Yorkers for water supply, the assertion in the RDSGEIS that "one quarter of New Yorkers … rely on groundwater as a source of potable water" (Id.) understates the number of people who may be affected by groundwater contamination

RDSGEIS Figure 2.1 shows that the north end of the shale parallels a large principal aquifer north of Syracuse. This coincidence deserves explanation at some point in the document.

The RDSGEIS mentions that one quarter of New Yorkers rely on groundwater as a source of potable water (RDSGEIS, p. 2-20). This downplays the connection of groundwater with surface water; many aquifers support stream flow, especially during low flow period, therefore aquifer contamination potentially affects many more people.

Safe yield (RDSGEIS, p. 2-29) is an outdated and flawed concept which should not be repeated in the RDSGEIS. It is flawed because all pumping depletes the aquifer, which contradicts the definition of the phrase (Id.). The preferable concept is sustainable yield which is the amount of water that can be pumped without having significant negative effects on the aquifer and on resources connected to that aquifer; what is significant is a societal question related to the values that depend on the aquifer (Alley et al, 1999).

Presence of Fresh and Salt Water

The federal Safe Drinking Water Act (SDWA) defines an underground source of drinking water (USDW) as "[a]n aquifer or portion of an aquifer that supplies any public water system or that

contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer" (http://water.epa.gov/type/groundwater/uic/glossary.cfm). However, NYSDEC apparently ignores this federal requirement where it specifies that surface casings be extended to 75 feet below the transition from fresh- to saltwater but also specifies 850 feet below ground surface (bgs) as a "practical generalization for the depth to potable water", the point at which near-surface freshwater transitions to saline water, which corresponds to 1000 ppm total dissolved solids (TDS) and 250 mg/l chlorides (RDSGEIS, p. 2-23, 6NYCRR §550(at)). The NYSDEC regulations, by only protecting water to a 1000 ppm cutoff for TDS may not provide protections that for some waters that could apparently meet the definition under the SDWA.

The hydrogeology of southern New York over the Marcellus gas play does suggest that there may be very little water with a TDS higher than the threshold that could actually be developed. Williams (2010) found that freshwater transitions to salt water at about 200 feet bgs in valley areas and about 800 ft bgs in upland areas in three counties in the middle of the Marcellus shale gas play. There was uncertainty around the depth estimates with some freshwater observations at deeper depths. Also the distinction between fresh- and saltwater in his survey of both water and gas wells was based on taste tests rather than any scientific measurement. Williams et al (1998) found similar results in similar geology just across the border in Pennsylvania. Many electric conductivity logs for bedrock water wells in the north Catskill Mountains (Heisig and Knutson 1997) showed that EC would jump from low values representing freshwater to high values representing salt water in a short transition zone or threshold. This suggests that many of the bedrock areas over the Marcellus shale gas play have either high-quality, low-TDS water, or very poor-quality high-TDS water; few wells apparently have water quality near the actual cut-off value. Considering the geology of the area, the zones that have high TDS are also mostly very low hydraulic conductivity zones, so they would not be considered an aquifer because they would not produce sufficient water to support a water supply.

However, the presence of salt water welling up under the alluvial aquifers, which often coincides with fault zones, suggests that salt water does move upward in fractured areas. Water with TDS up to 10,000 ppm may be developable in these higher conductivity fracture zones. In these areas, the NYSDEC regulations may be violating the SDWA requirements to protect USDWs, although the regulations regarding development in primary and principal aquifer may limit drilling in the areas underlain by fractured rock which could have developable high TDS water. Regardless of those aquifer regulations, the threshold for protection should include all areas that qualify as underground sources of water as defined under the Safe Drinking Water Act. These would include waters with TDS up to 10,000 ppm where they exist in an aquifer, and to 1000 ppm or

250 mg/l Cl- in areas underlain by unconductive bedrock. See the separate technical review submitted by Harvey Consulting LLC, for further discussion of the requirements on the SDWA.

- The operator should extend the surface casing to below the 10,000 ppm TDS threshold, unless the operator can show that the formation containing groundwater between 1000 and 10,000 ppm could not produce water in usable quantities. In this case, the operator should extend the surface casing to below the 1000 ppm TDS threshold.

The RDSGEIS does not indicate that the regulations will require the driller to actually locate the transition depth, which would define the depth below which the surface casing would extend a minimum of 75 feet (RDSGEIS, p. 7-50).

- *The regulations should require the operator to complete geophysical logging, including specific conductance logging, prior to casing the well, to determine the actual depth of protected water to which to apply the casing regulations.*

Hydrogeology of the Shale

RDSGEIS Section 4.0 covers Geology, but leaves out most of the important aspects of the Marcellus shale. There is no discussion of hydrogeology of the formations between the targeted shales and the surface, including no discussion of the hydrogeology of the shale itself beyond mention of the permeability. This failure means there is no baseline against which to compare the hydrogeologic changes caused by fracking. There is no hydrogeologic description of the sedimentary layers between the shale and the surface other than very cursory mentions of how it has low permeability. The lack of data on the hydrogeology of formations between the target shale and ground surface is important because NYSDEC relies on geology to "limit or avoid the potential for groundwater contamination" (RDSGEIS, p. 6-2).

Formations that lie between the shale and the surface are generally considered a natural control on fracture propagation and contaminant transport vertically from the shale (RDSGEIS, p. 6-54). RDSGEIS Figure 4-2 does not support the statement that overlying formations will prevent vertical movement of contaminants (RDSGEIS, p. 6-54) because it shows that layers above the Marcellus are primarily sand, limestone, and shale, with no indication of the proportion of each, which controls their conductivity and their propensity to propagate fractures. Most important from the perspective of contaminant transport from the shale to the surface is the prevalence of fractures, both due to faults and otherwise. Faults could be a pathway for vertical contaminant transport (Osborn et al 2011; Myers in review) and could also allow fractures to propagate further from the shale. The RDSGEIS discusses faults only with regard to present day seismicity and the potential for induced seismicity and presents an outdated map (Isachsen and McKendree 1977). A more detailed an integrated analysis of faults and fractures revealed there are many more faults in New York's Appalachian Basin than

previously suspected (Jacobi 2002). The RDSGEIS should include up-to-date information and acknowledge that more faults are probably yet to be found.

There is little information provided in the geology or hydrogeology sections about the make-up of the shale, beyond the amount of organic carbon. The geology chapter does not even mention the presence of pyrite in the Marcellus shale, although there is a brief reference to it for the Utica shale. The sections on "Solids Disposal" mentions pyrite and acid rock drainage of cuttings derived from the Marcellus shale. "As the basal portion of the Marcellus has been reported to contain abundant pyrite (an iron sulfide mineral), there exists the potential that cuttings derived from this interval and placed in reserve pit may oxidize and leach, resulting in an acidic discharge to groundwater, commonly referred to as acid rock drainage (ARD)" (RDSGEIS, p 7-67). ARD will be discussed more below in the Regulations section.

Most industry references state the Marcellus shale is "low-permeability" (RDSGEIS, p. 2), and the proposed regulations apparently rely on this categorization, although not all sources agree with it. Soeder (1988) described Marcellus shale as "surprisingly permeable" and presented data showing the permeability ranges up to 60 microdarcies, as compared to the Huron shale with permeability two orders of magnitude lower. Most reported permeability values are estimated from core samples, but, in a hydrogeologic sense, these estimates do not represent the formation-wide conductivity; point estimates due to scaling effects can be several orders of magnitude less conductive than the formation as a whole due to preferential flow through fractures (Schulze-Makuch et al, 1999), which are prevalent in this area. RDSGEIS Figure 4-2 also does not show the fractures in the overlying formations which prevail throughout New York including in the Marcellus shale zone (Myers in review).

The assertion that the shale requires fracturing "to produce fluids" (Id.) does not prove that the shale above the Marcellus is equally poorly transmissive. Shales above the Marcellus have not apparently trapped gas or fluids for significant time periods, a fact which undercuts the claim they are not transmissive or there is a lack of vertical flow. Fractures that go out-of-formation above the shale connect the shale with the much more transmissive formations above the shale.

The Geology section should also discuss general groundwater flow paths in the formations above the shale; this should include vertical gradients and recharge zones.

- *The RDSGEIS should discuss the hydrogeology of the formations between the targeted shale and ground surface, including data on the hydraulic conductivity of the formations.*

- *The RDSGEIS should also map the groundwater gradients for the formations just above the targeted shale using water level data obtained from geothermal applications and previous deep wells.*
- *The NYSDEC should require the industry to do a seismic survey to locate faults near proposed drilling, within half a mile of the center of the well pad or 1000 feet beyond the projected end of the horizontal wells, whichever is further from the well pad.*
- *The RDSGEIS should include up-to-date fault mapping.*
- *Industry should be required to complete and provide to the NYSDEC geophysical logging of the formations above the targeted shale showing fractures, lithology, and groundwater characteristics.*

Description of Hydraulic Fracturing

RDSGEIS Chapter 5 describes the fracking process, but it does not describe what actually happens to the shale – what does it look like after fracking and what are its properties. It is much more permeable to gas flow, perhaps substantially so, therefore it must also be much more transmissive to water flow. With up to an expected 40,000 horizontal wells over the next 30 years in New York (RDSGEIS, p. 6-6), the properties of the shale, which currently is an aquitard, will change substantially. The RDSGEIS completely fails to address these changes.

Industry designs fracking jobs to keep the fractures in the shale, but data show that the results of the fracking do not always or even often verify the design. The industry rarely monitors or measures the actual extent of fractures (RDSGEIS, p. 5-88), beyond monitoring pressure and injected fluid during fracking. The RDSGEIS references Fisher (2010) as being proof that fractures do not extend into the aquifer zone, but his data actually show that fractures commonly go out of formation (Figure 1). His data show many instances of the top of the fracture zone being more than 1000 feet above the centerline of the shale. As the depth to the centerline of the shale decreases from 8000 to 5000 feet, the vertical fracture growth also appears to decrease from 2000 feet above to 500 feet above the centerline of the shale. The apparent trend to fracture growth above the formation decreasing with decreasing depth may relate to the pressure on the rock or its hardness. The data were not sorted according to formation type and there is no data concerning shale thickness, therefore it is unknown whether fractures extend further in some types of rock or whether out-of-formation fractures are more common with thinner shales.

- *The RDSGEIS should not rely on industry's alleged intent to avoid out-of-formation fracking as a means of preventing the consequences of out-of-formation fracking.*

- *The RDSGEIS and regulations should require geophysical logging and microseismic tests to map how far fractures extend out of formation, and the density of the fractures in different formation. This information should be publically available so that all companies can benefit from experience and so that the public can better understand the process.*

FIGURE 2

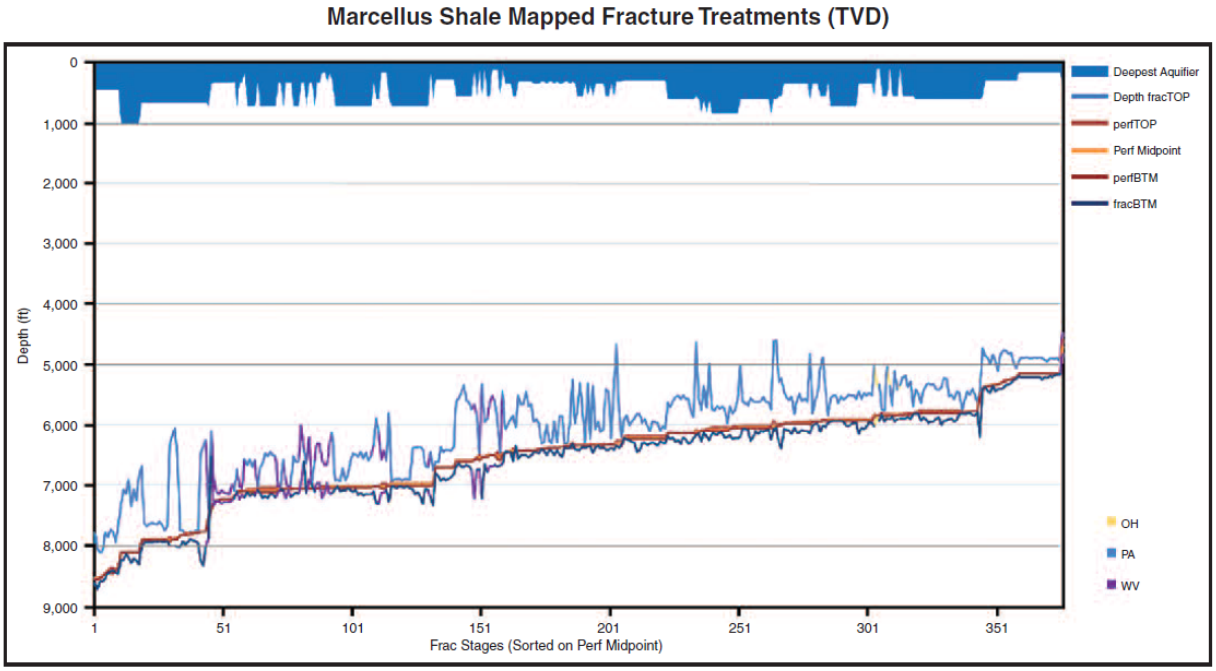


Figure 1: Figure 2 from Fisher (2010) showing the well centerline and a depth to the top of the fracture zone.

It is common practice to compare pressure and flow rate monitoring results from fracking operations to expected values from pre-fracking modeling as a method for evaluating the results of a fracking procedure (RDSGEIS, p. 5-88). Considering that many things affect the pumping flow rate, including pores between the well and the leading extent of the fluid moving away from the well, hydraulically it is difficult to imagine that a significant pressure drop would accompany the leading edge of the fluid reaching surrounding formations. Fracturing into surrounding formations would not bring additional water into the shale, as suggested (Id.), because of the pressures as described elsewhere (Myers in review). The increased porosity in the shale would release substantial brine bound in the shale.

Fracking injects up to 7.2 million gallons of frack fluid into the shale over a well bore up to 4000 ft long – the RDSGEIS suggests these are general upper limits based on fracking in the Marcellus shale in other states. Fractures form or widen as the injection pressure exceeds the normal stress in the shale (RDSGEIS, p. 5-95). The injection would slowly displace any water and gas

that exists in the (extremely small) pore spaces near the well; it would push the natural fluid away from the well bore. Because less than 35% of the injected fluid returns to the well as flowback, a significant proportion of the injected fluid remains underground, presumably occupying pores extending out from the well bore. Assuming a job injects 5 million gallons and there is 20% flowback, approximate average values, and 10% effective porosity resulting from the fracking, the fluid could occupy all pore spaces in a 21-ft diameter cylinder centered on the well. Assuming a more realistic resulting effective porosity of 1%, the fluid could fully occupy the pores out to 62 feet in all directions from the well. Fluids that existed there prior to fracking would be pushed further from the wellbore, likely into surrounding formations. Thus, simple consideration of the volume of fracking fluid injected shows that fluid would move far from the well bore and displace formation fluids even further The calculation does not account for pre-existing preferential flow paths or heterogeneities in the direction that fractures develop, so the fluid would likely move further from the well bore in some directions. The fluid would also follow pathways created by the fractures above the shale, thus fluids could end up much further from the well bore than simple considerations would indicate. .

Shale NG development will affect a large proportion of the shale in New York with fracking fluid, as can be shown by comparing expected fracking fluid volumes with shale volume. The RDSGEIS does not indicate the total area of Marcellus shale within New York. However, Figure 2 in Myers (in review) shows the extent of shale within New York to be 18,680 sq miles. Assuming an average thickness of 100 ft, the total volume is 5.2×10^{13} ft^3. If the expected 40,000 wells are all developed in the Marcellus shale, the injected water volume will approximate 2.1×10^{10} ft^3, which at porosity of 0.01 means that fracking fluid would occupy all of the pores in about 4% of the total Marcellus shale volume[1]. This assumes that none of the fluid reaches surrounding formations, which as shown above is unlikely. It is also unlikely that development will be evenly spaced over the shale as supposed in this calculation, therefore the effect in areas of concentrated development could be underestimated.

Fracking efficiency does not improve if the well spacing is significantly less than 300 m, or about 1000 ft (Krissane and Weisset 2011). It is therefore appropriate to assume that fracking changes the shale over the entire spacing unit, or an area of 660 by 4000 ft. The total area affected by 40,000 wells would be about 3800 square miles, which is about 20% of the total shale area in New York. Based on the extent that injected fluid reaches from the well and the frequency of out-of-formation fracturing (Fisher 2010), it is reasonable to conclude that most fracking affects the shale to its edge. Fracking, based on these assumptions, will significantly change the hydrogeology over at least 20 % of a shale aquitard that extends over 18,680 square miles of New York. Because not all of the total area will be developed, it is a good assumption

[1] This calculation assumes 5,000,000 gallons injected per well and 20% flowback for each of 40,000 wells.

that where development actually occurs, fracking will substantially change the shale hydrogeology.

The statement, that "the volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer" (RDSGEIS, p. 6-53), is also misleading. The total proportion of pores actually filled by injected fluid may be relatively small, but combined with displaced existing brines the injection will affect groundwater over a much larger proportion of the pores. The boundary between salt and freshwater may be displaced or disrupted by advection and dispersion of and by fluids associated with fracking. Additionally the changed properties of the shale over a large area will affect the upward movement of the natural brines. Simple consideration of advection and dispersion shows that the current balance between fresh and salt water could be substantially upset by fracking.

The RDSGEIS also erroneously claims that the pressure applied for injection will dissipate immediately upon cessation of pumping; in the well bore that may be correct, but the fact that pressure exists to push fluid back into the well bore proves that residual pressure remains in the shale and possibly beyond. The statement that "the amount of time that fluids are pumped under pressure into the target formation is orders of magnitude less than the time that would be required for fluids to travel through 1,000 feet of low-permeability rock" (RDSGEIS, p. 5-94, p. 6-53) is technically correct but highly misleading because pressures and conditions for transport from the shale to the near surface will exist long after fracking has finished. Fluids can move away from the well bore at distances from the well bore after the injection ends until the pressure has dissipated; the contrary statement (RDSGEIS, p. 5-94) is wrong in that respect. Myers (in review) describes the modeling of injection and its effect on the pressure distribution in detail. The following is a simpler and more accurate description that should be what appears in the RDSGEIS:

> Hydraulic fracturing involves high pressure injection of fracking fluid into the shale from a horizontal well. This injection fractures the shale and increases the size and connectivity of existing pores. The high pressure creates a pressure gradient from the well to a point in the shale just beyond the expanding volume of injecting fluid where the pressure remains equal to background. If the fluid disperses from the well evenly, the volume will be a cylinder. As injection continues, the radius of the cylinder increases and pressure gradient is from the well to the edge of the cylinder. Offsetting the decreased pressure gradient is an increased effective cross-sectional area for the fluid to cross. The flow away from the well fractures the shale, creating new fractures and increasing the size of the existing fractures. When injection ceases the pressure in the well drops immediately to atmospheric pressure coincident with the well-bottom depth. However, the pressure in the shale begins to drop more slowly, initially equals that caused by injection. Flow away from the well continues as the pressure in the reservoir

created by the HVHF treatment moves fluids towards the well and away from the well both but since there is no more pressure being applied at the well the pressure in the shale near the well begins to drop.

Descriptions in the RDSGEIS (p 5-94) are therefore wrong. Fracking is a transient situation wherein a pressure divide, where the pressure is higher between the well and the end of the fluid, sets up with some fluid movement toward the well and some away from the bore continues. The modeling (Myers in review) shows that this requires about 90 days to effectively dissipate. This counters several statements in the RDSGEIS implying that all fracturing and flow from the well bore ceases at the end of fracking, in about five days.

The claim that the flow direction away from the wellbore would be reversed during flowback (RDSGEIS, p. 6-54) also cannot be correct if only 10 to 30% of the injected fluid actually returns to the well. Some must continue to flow away from, or at least not toward, the well.

NYSDEC makes an unreasonable assumption regarding the flow around the shale after fracking, regarding a discussion of the period between fracking operations if refracking would occur. "It is important to note, however, that between fracturing operations, while the well is producing, flow direction is towards the fracture zone and the wellbore" (RDSGEIS, p. 5-99). Because the goal is to attract gas from the shale, any such low pressure would likely affect just the fracked shale, not formations away from the shale in which fluids would flow according to the background hydraulic gradient. That a small amount of formation water may be produced with time indicates that water from only a small portion of the shale near the well flows toward the well. If the natural gradient in formations above the shale has a vertical component, there will be upward advection of water and contaminants away from the shale.

- *Measurements of the water pressure profile should be made in each well prior to fracking, as it is drilled and before it is cased. This could be a part of the geophysical logging process*.

NYSDEC assumes that it will be rare for a well to be refracked, that is, to repeat the fracking operation years after initially completing it, inappropriately relying on "Marcellus operators'" assurances without reference to a source (RDSGEIS, p. 5-98).

Contaminant Transport from the Shale

The RDSGEIS completely dismisses the concept of vertical contaminant migration from the shale to fresh-water aquifers. Statements suggesting that the only way for the public to be exposed to fracking fluid would be through an accident or spill (RDSGEIS, 5-74) reflect the

dismissal of the potential long-term transport from the shale. This section reviews the evidence and potential for contaminant transport from the shale.

Claiming that regulatory officials from 15 states have "testified that groundwater contamination as a result of the hydraulic fracturing process … has not occurred" (RDSGEIS, p. 6-41 & 6-52) is misleading because they have simply never looked for contamination beyond reports from water well owners. There are no monitoring well networks designed to monitor contaminant transport upward from the fracked shale. The upward transport could also take years, decades, or centuries, not just the few days considered in the RDSGEIS. They are wrong to suggest there is no evidence for such transport.

Two reports have documented or suggested the movement of fracking fluid from the target formation to water wells (EPA 1987; Thyne 2008) linked to fracking in wells. Thyne (2008) had found bromide in wells 100s of feet above the fracked zone. The EPA (1987) documented fracking fluid moving into a 416-foot deep water well in West Virginia; the gas well was less than 1000 feet horizontally from the water well, but the report does not indicate the gas-bearing formation. There is also recent evidence of fracking fluid reaching several domestic drinking water wells near Pavillon, WY from a deep source in a sedimentary sandstone and shale formation Diquilio et al 2011). Deep monitoring wells (depth not specified) have detected synthetic organic compounds including glycols, alcohols, and 2-butoxyethanol, BTEX (including benzene at 50 times the MCL), phenols, trimethylbenzenes, and DRO. Dissolved methane was found at near-saturation levels with an isotopic signature similar to production gas. The EPA identified three pathways for fluid movement. One was nearby wellbores. The second was fluid movement from low permeability sandstone into more conductive sandstone nearby. Third was out-of-formation fractures forcing fracking fluid into overlying formations. NYSDEC should consider this example as a cautionary tale of the potential for vertical movement of fracking fluid to near-surface aquifers.

Methane contamination has been observed to occur in many areas near fracking operations. The RDSGEIS acknowledges that gas migration occurs (RDSGEIS, p. 6-42), but suggests it is limited to well construction problems. This assumption ignores the studies which link the source to much deeper formations (Osborn et al 2011, Thyne 2008). Myers (in review) and Osborn et al (2011) indicate that gas transport could indicate pathways which could also be longer-term fluid pathways; if there is a pathway for gas, there is also a pathway for water.

The RDSGEIS dismisses diffusion of chemicals from the shale to the surface because this would dilute their concentrations; this is correct, but diffusion is only a minor process in the movement of chemicals to the surface and is the wrong process to analyze for consideration of

whether vertical transport could occur. Contaminants move by advection, dispersion, and diffusion, with the later being a minor component. Advection would be the most likely transport process (Myers in review). Upward movement of chemicals could occur by advection wherever there is an upward vertical component to the hydraulic gradient; fractures and faults would enhance that flow. Myers (in review) simulated transport through the bulk media as requiring from 100s to 1000s of years, depending on hydraulic properties and gradient; fractures substantially decreased that simulated time.

The RDSGEIS relies on an analysis by ICF (2009), included in the RDSGEIS as Appendix 11, for its dismissal of potential vertical contaminant transport. Dismissing the potential for such transport based on the gradient occurring just for the time of fracking simply illustrates a lack of understanding of the process and associated groundwater and contaminant flow. ICF (2009) had been part of the 2009 version of the DSGEIS. Appendix A of this technical memorandum reviews ICF (2009) again in detail and Appendix B presents a copy of a journal article (Myers in review), which analyzes in detail the potential for transport from the shale to the surface.

The RDSGEIS should reconsider some of its assumptions and implement several regulatory changes, as specified here:

- *ICF (2009) should be removed in its entirety and substituted with an analysis that at least acknowledges the potential risk for long-term contaminant transport from the shale to the surface. All citations to and conclusions based on ICF (2009) should also be removed from the RDSGEIS.*
- *The RDSGEIS should include the foregoing recommendations concerning hydrogeology, and regulations should be promulgated specifically requiring the delineation of properties of the geologic formations above the shale, the locations of fractures, and mapping of the hydraulic gradients near the proposed drillsites.*
- *The RDSGEIS and regulations should require driller to implement a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport, as described below in the section concerning groundwater monitoring.*

Other Pathways for Groundwater Contamination

Section 2.4.5 incorrectly claims that "[i]mproperly constructed water wells can allow for easy transport of contaminants to the well…" (RDSGEIS, p. 2-22). Transport "to the well" depends on flowpaths and gradients near the well which would only marginally be affected by well construction. Improper water well construction does allow transport of contaminants along the casing which could allow contaminants to move among aquifers, once the contaminants reach

the well. Improperly constructed wells can allow contaminants from aquifer layers which were not intended to be screened to transport to the producing layers.

Flowback and produced water are important potential contaminants, primarily in the potential for blowouts or spills just after fracking and in the potential for leaks from the well bore. Estimates are that from 9 to 35% of the injected fracking fluid, expected to vary from 2.4 to 7.8 million gallons per well, would return as flowback (RDSGEIS, p. 5-99). This is a total flowback of 216,000 to 2.7 million gallons per well (Id.). Estimates also indicate that up 60 percent of the flowback would return within the first four days after fracking ceases (RDSGEIS, p. 5-100). The upper estimate based on these ranges is that 60 percent of 2.7 million gallons, or 1.62 million gallons of flowback will occur within four days of the cessation of fracking. Modeling in Myers (in review) confirms both the relative proportion of injected fluid that becomes flowback and the rapid rate.

Flowback is a mixture of returning fracking fluid and formation fluid, but the limited chemistry data presented in the RDSGEIS suffers from being a single sample per well (RDSGEIS, p. 5-105). The RDSGEIS states that some of the data was provided by the Marcellus Shale Coalition, an industry group, but without reference or actually providing the data; it is not possible for the reader to assess or draw independent conclusions that might differ from the statements in the RDSGEIS. The available data does not apparently allow an assessment of the proportion of shale to injected water. For example, samples with very high salt content probably consist more of shale brine than fracking fluid. RDSGEIS Table 5.10 demonstrates, by its illustration of poor water quality, that the water must be contained. The minimum, median, and maximum for TDS, at 1530, 63,800, and 337,000 mg/l, respectively, suggests the proportions vary widely but that more than half of them are saltier than ocean water. The range in chemicals such as benzene, at 15.7, 479.5, and 1950 ug/l, shows that some flowback could be extremely toxic; the NY MCL for benzene is 5 ug/l, thus most of the samples above detect exceed the standard for this contaminant. Because of the toxic chemistry of flowback water, much more data is necessary, as specified here:

- *The RDSGEIS should present temporal flowback data from specific wells, in tabular or graphical form.*
- *The RDSGEIS should present an appendix with raw data provided by the Marcellus Shale Coalition or link to the data on the internet*.
- *Table 5.10 could be made more understandable by including the detect and MCL levels.*

The RDSGEIS promises that flowback would be contained in “water-tight tanks” for onsite handling (Id.), but the document does not discuss the sizing of the tanks. The proposed regulations address flowback and requirements for capturing it at many points (6 NYCRR §560),

but also fails to specify a size. For example, the operator must include " the number and total capacity of receiving tanks for flowback water" (6 NYCRR § 560.3(a)(12)), and must have secondary containment, "as deemed appropriate by the department"…"sufficient to contain 110 percent of the total capacity of the single largest container or tank within a common containment area" (6 NYCRR § 560.6(x)(26)(i)). Because there are no specifications for the size of the "single largest container", the required secondary containment sizing is not useful.

- *The RDSGEIS and proposed regulations must specify the necessary total capacity for tanks to contain flowback. The required capacity must reasonably exceed the expected flowback as discussed above. It must be able to capture within four days, 60 percent of the 35 percent of the maximum amount of fluid to be injected for fracking.*

RDSGEIS Chapter 5 lists many chemicals that could be used in fracking fluid, but does not list any properties of these chemicals which could affect their flow through soils or through groundwater. The RDSGEIS does not provide data regarding whether and how much they will be attenuated. However, the RDSGEIS inappropriately relies on attenuation (p. 6-53) to mitigate against the potential for long-distance transport.

- *The RDSGEIS should either provide data concerning the transport properties of the various chemicals or not rely on attenuation as a means of mitigating the transport which could results from spills and leaks.*

Groundwater Quality Monitoring

The previous sections of this report have highlighted the poor water quality of fluids associated with fracking operations – the fracking fluid itself and the produced shale-bed water – and the various pathways for aquifers to be contaminated. Small quantities of either of these fluids can significantly pollute groundwater and surface water. The RDSGEIS provides some setbacks in an attempt to protect various receptors – wells, aquifers, or streams – and the adequacy of these is discussed below. With the potential for spills and leaks from multiple sources associated with these operations, the requirements for groundwater quality monitoring in the RDSGEIS and the regulations is paltry and insufficient, as described here.

The proposed monitoring consists only of testing existing private water wells within 1000 ft of the drill site, or to 2000 ft if none are located within 1000 ft (RDSGEIS, p. 1-10, 7-44). While this is necessary for the protection of the well owner, it is insufficient for the long-term protection of the aquifer. Domestic wells have not been designed to function as water quality monitoring wells which causes many problems in sampling and interpreting the data. Thyne explains clearly why domestic wells are poor monitoring wells:

> First, the number of domestic well sample points is far exceeded by the potential point sources (gas wells). Domestic wells are much less than ideal for sampling purposes. Domestic wells are not placed to determine sources of contamination in groundwater. They are not evenly spaced around gas wells or within close enough proximity to determine the presence of chemicals associated with methane that degrade rapidly. Domestic wells are generally screened over large intervals making vertical spatial resolution for samples difficult nor are the wells are not constructed to facilitate measurement of water table elevation or downhole sampling. This forces sampling to occur at the surface after pumping raising the possibility of sampling artifacts. In addition, since domestic wells are the sole source of drinking water for individual properties, it is difficult to arrange access to take samples due to privacy issues, and the County may bear potential liability for damage during sampling and interruption of water supply. (Thyne 2008, p 10-11)

A monitoring well system should be designed so that a contaminant plume will neither pass horizontally between the monitoring wells nor above or below the screened interval. The best way to be certain of intercepting a contaminant passing a point in an aquifer is to span the entire aquifer with well screen. A long screen may increase the chances of detecting the presence of a potential contaminant which may indicate the site being monitored has developed a leak, but will dilute the concentration by mixing contaminated water with cleaner water. A sample extracted from such a well will be a conglomerate of the chemistry of the entire screen thickness; if the screen spans multiple lithologies, the water within the well bore will not be representative of any lithology (Shosky, 1987). It can only be effective only for substances which do NOT naturally exist in the region of the aquifer. Monitoring with long screens is good only for presence/absence determinations.

Concentrations vary throughout an aquifer, both vertically and horizontally. The concentration determined from any well will represent an average over the entire screen length. Therefore, to monitor trends in concentration, screens should span representative vertical sections

The spatial layout of the monitoring well system should be based on the conceptual flow and transport model for flow from the gas well through the aquifer, which includes flow pathways and possible contaminant dispersion. Monitoring wells should be placed as close to the expected flow path as possible, where the concentration will be highest. However, because of uncertainty in the prediction of the flow path, monitoring wells should also be spaced laterally away from the expected flow path. These lateral wells should detect lower concentrations than the one in the predicted flow path. If the lateral wells actually have higher concentration, the predicted flow path may be incorrect and monitoring wells should be added further from the predicted flow path to improve the understanding of the flow and movement of the contaminant plume.

Monitoring wells or piezometers should be placed close to the potential source for early detection, but also at a distance from the source to increase the chances that they will intercept the contaminant and to assess the rate of contaminant movement. If many wells detect the contaminant, the concentration variation would indicate the degree of dispersion. Denser well networks will have a better chance of detecting the contaminant and providing accurate description of it dispersal.

Considering the above fundamentals of a monitoring system, the following recommendations, in addition to sampling the existing private wells, should be added to the RDSGEIS and partly replace proposed regulations in 6 NYCCR §560.5(d)

- *The operator should prepare a conceptual flow path model for groundwater and contaminant transport from the drill pad to and through nearby aquifers.*
- *As part of the conceptual model, the operator should estimate the distance that a contaminant would travel from the well pad in various time periods, including one month, six months, one year, and five years.*
- *Dedicated groundwater monitoring wells should be reasonably located along and perpendicular to the projected flow path out to the five-year travel distance. At a minimum, there should be a transect of monitoring wells/piezometers at the one-month travel distance from the well and halfway between the well and important receptors, meaning wells or discharge points such as springs or streams.*
- *Monitor wells should span the surface aquifer and piezometers should have multiport sampling capabilities for twenty foot intervals at the top of the saturated zone and every 100 feet to the bottom of the freshwater zone. This will help establish vertical concentration and hydraulic gradients.*
- *The monitoring system should be established to establish baseline data including seasonal variability for at least one year prior to drilling and fracking.*

Monitoring transport from the deep shale is more difficult because a substantial flux of contaminants could be released from most anywhere in the fractured shale as a result of oil and gas development. Time intervals for transport could be more than 100 years, but fractures could decrease the time frame to as short a time as a few years. Fracture zones therefore could be monitored, but if they are known the industry should avoid fracking near them, both to avoid vertical transport and induced seismicity. It is therefore reasonable to require a dedicated monitoring well in the middle of each well pad wherever there is an upward flow gradient.

- *Industry should establish a multiport piezometer system from the shale to the bottom of the freshwater zone in the center of all well pads.*

- *The industry should provide the funding to maintain the piezometers system for at least 100 years beyond the end of gas production, to account for the long potential travel times.*

WATER RESOURCES

This section concerns primarily the controls on making water withdrawals for fracking. The section focuses on surface water diversions but also considers diversions from aquifers.

The RDSGEIS notes correctly that without proper controls, the withdrawals of water from streams and aquifers to use in fracking could have significant ecologic and hydrologic impacts (RDSGEIS, p. 6-2). The "natural flow paradigm" is a good description of the interdependencies of the stream ecology with all of the hydrologic regimes (RDSGEIS, p. 6-4). The description of the depletion to an aquifer and the interconnection of aquifers with surface water (RDSGEIS, p. 6-5) is also good. Treating the withdrawals as consumptively lost to the system (RDSGEIS, p. 6-9) is appropriate because in essence, with recycling of flowback, the water will not return to the system. These are acknowledgements which should lead to good regulation of withdrawals, if properly considered in the rulemaking.

The discussion and comparison of the withdrawals for fracking with statewide water uses (Withdrawals for High-Volume Hydraulic Fracturing, RDSGEIS, p 6-9 thru 6-13) are scientifically unsupported and irrelevant;. The potential impacts of withdrawals are a matter of scale and depend on their size, the size of the stream, and antecedent moisture conditions.

Much of the regulation of withdrawals from streams focuses on passby flows. The RDSGEIS defines a passby flow as "a prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring" (RDSGEIS, p 2-30) which also specifies a low flow condition "during which no water can be withdrawn" (Id.). Specific definitions will be discussed below, but in reality the lower specified values can allow significant damage to occur to streams, especially smaller ones. If the required passby flow is small compared to the average, meaning it has a long return interval, it will only rarely restrict water withdrawals. If flows on the river can be reduced to a low passby flow, then diversions can reduce the flow to low, long return interval rates much more frequently; this is tantamount to imposing low-frequency, high-damaging, drought on the streams much more frequently.

The Delaware River Basin Commission (DRBC) does not have a specific passby flow requirement and usually uses the 7Q10 flow, the seven-day low flow with a ten-year return interval, for water resources evaluation (RDSGEIS, p. 7-13). The RDSGEIS indicates this is not protective (Id.) and as described in the previous paragraph, it would allow the 10-year low flow to manifest

much more frequently. The Susquehanna River Basin Commission (SRBC) regulations are more complicated, but generally use the 7Q10 or from 15 to 25 percent of the average daily flow (RDSGEIS, p 7-15, 16). Neither is protective and the NYSDEC proposes to use the natural flow regime method (NFRM) method for all regions (RDSGEIS, p 7-16).

The RDSGEIS expresses the intent to use the NFRM only in permit conditions, however, as the document acknowledges that guidance has not yet been completed (RDSGEIS, p. 7-3). As authority, the RDSGEIS cites 6 NYCRR § 703.2, which states that "[n]o alteration that will impair the waters for their best usages" will be allowed. "For the purpose of this revised draft SGEIS only, the Department proposes to employ the NFRM via permit conditions as a protection measure pending completion of guidance." (Id.). NYSDEC also indicates that the requirement could be "imposed via permit condition and/or regulation" (RDSGEIS, p. 7-22).

- *NYSDEC must include the requirement for using the NFRM in the regulations if it is to be consistently enforceable; the proposed regulations do not currently require use of the NFRM to establish the requisite passby flow in a stream.*

The NFRM attempts to protect the distinctive flow patterns for each stream, including the "variable magnitude, duration, timing, and rate of change of flow rates and water levels" (RDSGEIS, p 7-18). The RDSGEIS proposes to use the "Q75 and/or Q60 monthly exceedence values for establishing passby flows" (Id.). An Qx exceedence value is the flow rate which is exceeded x percent of the time. Another way of considering the Q75 and Q60 exceedance values is that the passby flow would be greater than the flow which the stream exceeds 25 or 40 percent of the time. This is much higher than a 7Q10 flow. However, in a small stream, diversions could change a flow regime from wet (higher than average) to significantly below average.

NYSDEC appears to intend that if the watershed exceeds 50 square miles, the passby flow will be Q75 for the winter/spring months of October through June and Q60 for the summer months of July through September, whereas for smaller watersheds (Area<50 sq miles), the Q60 value applies all year (RDSGEIS, p 7-19). NYSDEC at least recognizes that small streams need more protection and that low flows can be more critical during the summer when temperatures are higher. This means that at least 40 percent of the time, withdrawals will not be allowed. For another short time period (up to the time for which the actual streamflow and the required passby flow is less than the preferred withdrawal rate), withdrawals will be limited to prevent the streamflow from being reduced to below the passby flow.

The RDSGEIS does not discuss how the recommended passby flows were chosen, in terms of habitat protected. There is an implication that Q60 and/or Q75 mean the same amount of

habitat would be protected; this may simply be incorrect because streams are not created equal. The NYSDEC should apply a second filter and actually require a determination of the habitat at Q60 and limit the change in habitat. This is one advantage of the Susquehanna River Basin Commission method (RDSGEIS, p 7-15, -16).

The flow estimation method assumes a linear relation between baseflow and drainage area (RDSGEIS, p 7-19). The assumption is that streamflow increases consistently in a downstream direction in proportion to the contributing drainage area. Because it is essential to the method, the RDSGEIS should present data to justify their assumptions. Analyzing streams with two or more gages, the Qx flow at one would be calculated according to the area proportionality relationship with the other gage; the RDSGEIS should present this type of verification to prove the method is suitable.

On streams without gages, the RDSGEIS indicates that NYSDEC will use factors developed from regression equations based on their location in New York (RDSGEIS, Fig 7.1, Table 7.2). The table provides coefficients in cfs/sq mi for the passby flow for the different geographic zone by month. Presumably, they are based on basin areas as discussed above, with different requirements for greater than and less than 50 sq miles. The RDSGEIS should compare values determined with Table 7.2 with the actual value determined for gaged streams to verify the table. Statements such as "[t]he passby flow requirement … would fully mitigate any significant adverse impact from water withdrawals" (RDSGEIS, p 7-22) are unsubstantiated and unjustified.

The passby flow requirements effectively ignore the potential cumulative impacts, irrespective of the following sentence: "The application of the NFRM to all water withdrawals to support the subject hydraulic fracturing operations would comprehensively address cumulative impacts on stream flows because it will ensure a specified minimum passby flow, regardless of the number of water withdrawals taking place at one time" (RDSGEIS, p. 7-25). The RDSGEIS continues by indicating that "significant adverse cumulative impacts would be addressed by the NFRM … because each operator … would be required, via permit condition and/or regulation, to estimate or report the maximum withdrawal rate and measure the actual passby flow for any period of withdrawal" (RDSGEIS, p. 7-25, -26). The RDSGEIS analysis of the prevention of cumulative flow impacts appears limited to these statements. Clearly, several concurrent withdrawals along a stream reach could cumulatively decrease the flow at the more downstream sites to less than the passby flow, if the timing of withdrawals is not controlled and if there are not adequate measurements ongoing at the site which compare the actual flow to the required passby flow. Short of establishing a gaging station with flow/stage relationship, it is difficult to measure flows frequently enough to monitor short-term flow changes, therefore it is unlikely that an operator would be able to react sufficiently to preserve the passby flow.

The following are recommendations for improving the passby flow requirement to be used by NYSDEC

- *The program must be codified into regulations.*
- *The methods for estimating passby flows at ungaged sites must be verified as to their accuracy.*
- *NYSDEC should coordinate operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.*
- *The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.*
- *Passby flows should be maintained with consideration to the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.*

NYSDEC recognizes that groundwater pumping could deplete streams and also recognizes that pumping effects on the aquifers must be limited (RDSGEIS, pp 6-5, -6). Regarding groundwater pumping, the "Department proposes to impose requirements regarding passby flows as stated in this document" (RDSGEIS, p 7-25). The RDSGEIS does not discuss how the potential impacts to a stream will be estimated or how passby flows will be maintained, especially considering the lag time between groundwater pumping and the time for effects to manifest in the streams.

- *NYSDEC should prohibit groundwater pumping in tributary watersheds when analysis indicates that the time for a pumping effect to reach the stream is less than 30 days.*
- *NYSDEC should require a suitable groundwater analysis to estimate the effect on groundwater discharge to streams.*

The RDSGEIS indicates that industry has begun recycling more of its wastewater (RDSGEIS, p. 1-2). Recycling flowback water is good for reducing the amount of water to be disposed of, but it will not significantly decrease the water volume needed for fracking because the amount recovered as flowback is just 10 to 30 percent of the amount originally injected. Tracking the flowback to be recycled should be part of the new "Drilling and Production Waste Tracking" process (RDSGEIS, p. 1-13).

PROJECT MITIGATION MEASURES

The primary mitigation schemes proposed in the RDSGEIS are setbacks, which the RDSGEIS treats as additional precautionary measures (RDSGEIS, p. 1-11). This section considers whether

the setbacks are sufficient or arbitrary. A list in section 1.8 introduces additional precautionary measures; they are repeated in section 3.2.4. The following lists the proposed mitigation setbacks from the RDSGEIS and provides brief comment:

> "Well pads for high-volume hydraulic fracturing would be prohibited in the NYC and Syracuse watersheds, and within a 4,000-foot buffer around those watersheds."

The primary pathway if wells are prohibited within 4000 feet of the watershed boundary would be underground, since topography would cause contaminants to flow away from the watershed boundary, assuming this coincides with a topographic divide. In general, 4000 feet is probably sufficient, but a site specific consideration of the geology should be included to ascertain that the groundwater divide would not place the well within the watershed and that geologic formations are not dipping in the direction of the watershed.

- *This setback is not specified in the regulations, but should be.*
- *The operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the prohibited watershed.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (6 NYCCR §560.4(a)(2),(subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing)"

The implication of only a 500 –ft setback is that there is no groundwater connection, but if groundwater in the bedrock connects with the aquifer, there is a potential for a rapid transport of contaminants from a spill through fractures to the aquifer. Contamination will easily spread through the highly conductive aquifer (RDSGEIS, p. 6-37). The risk to the aquifer would be the same as to the prohibited watersheds, so there is no reason the distance should be different. If the ground surface slopes from the well to the primary aquifer, there is a significant risk of a spill reaching the aquifer through surface channels.

- *The prohibition in* 6 NYCCR §560.4(a)(2) *should be increased to 4000 feet, unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.*
- *Additionally, the RDSGEIS should publish the area the Marcellus shale zone overlapped by primary aquifers and the area that would be included as buffer; this would help the public to understand how much land the prohibition affects.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (6 NYCCR

§560.4(a)(4)) (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing)"

Essentially, there is no reason for this offset to be less than the offset from a primary aquifer. Considering a public water supply well, the operator should be required to perform a capture zone analysis for the well, and if the well could draw contaminants from a spill to the well, the gas well should not be permitted in that location.

- *The setback for public water supply wells should also be 4000 feet.*
- *Additionally, the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.*

"The Department would not issue permits for proposed high-volume hydraulic fracturing at any well pad in 100-year floodplains". (6 NYCCR §560.4(a)(4))

For wells that might operate for 30 years, there is a 26% chance[2] of a 100-year flood occurring during the period the well would be operated.

- *Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.*

"The Department would not issue permits for proposed high-volume hydraulic fracturing at any proposed well pad within 500 feet of a private water well or domestic use spring, *unless waived by the owner*." (6 NYCCR §560.4(a)(4)), emphasis added.)

NYSDEC should not allow the owner to waive this requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.

- *6 NYCCR §560.4(a)(1) should be changed to remove the waiver from the water well owner unless the owner is required to disclose the waiver to a future buyer in perpetuity.*

In general, some of the points discussed above mention that NYSDEC will revisit the need for the setback in the future. These reconsiderations are not part of the regulations. If so, the NYSDEC should specify in detail the performance standards that must be met in order for the setback requirement to be relaxed, and should acknowledge that a supplemental EIS would be completed to consider those changes.

[2] The probability that a event with a p probability will occur during n observations (years) may be determined with a binomial distribution.

The RDSGEIS also specified the following factors which would require site-specific SEQRA analysis.

1) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone is shallower than 2,000 feet along any part of the proposed length of the wellbore.
2) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply.
These requirements should be considered together – if the top of the shale is less than 2000 feet bgs or 1000 feet below the bottom of the aquifer, a site-specific SEQRA review will be required. The depths seem arbitrary, and must be based on a perceived potential for vertical transport from the shale to the receptor.

3) Any proposed well pad within 500 feet of a principal aquifer:
The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.

4) Any proposed well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond:
Again, rather than allowing development subject toa site-specific study, development within 150 feet of these streams should be prohibited. It is difficult to imagine how study will prevent a spill which is, by its nature, unexpected.

5) A proposed surface water withdrawal that is found not to be consistent with the Department's preferred passby flow methodology as described in Chapter 7;
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6) Any proposed water withdrawal from a pond or lake;
7) Any proposed ground water withdrawal within 500 feet of a private well;
8) Any proposed ground water withdrawal within 500 feet of a wetland that pump test data shows would have an influence on the wetland:
Requirements 5 through 8 are acceptable limits for requiring site-specific study.

9) Any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure

This applies to areas outside the NYC watershed that contain NYC infrastructure (RDSGEIS, p 6-1). It is unclear whether there is any infrastructure that would actually be affected by fracking outside of the watershed. Fracking should not be allowed within 1000 feet of any NYC water supply infrastructure to prevent damage.

Acid Rock Drainage

The RDSGEIS refers in several locations to an acid rock drainage (ARD) mitigation plan which would be required for the on-site burial of Marcellus Shale cuttings (RDSGEIS, p 7-67). In general, our recommendation is that on-site burial not be allowed (see the report by Harvey Consulting, LLC). NYSDEC does not describe an adequate mitigation plan to prevent the leaching of ARD into groundwater. It does not specify testing which is essential to know how much neutralizing rock must be supplied.

For each well, prior to disposal of the cuttings, an adequate set of samples should be collected from the cuttings to test for acid generation. Adequate sampling would be representatively spaced along the horizontal well bore; initially, many samples would be needed to determine the variability among samples; samples every 100 feet would be desirable until sufficient data is collected from New York shales to characterize the variability along the horizontal well bore.

At least three types of testing should be completed:

- Acid base accounting – Modified Sobek procedure
- Net acid/alkaline production
- Meteoric water mobility testing – ASTM E-2242-02

These tests should provide adequate information to determine the amount of neutralizing rock which should be added to the cuttings to prevent ARD from leaching through the waste. Ideally, if the rock is potentially acid generating (PAG), kinetic tests should be completed to better assess the PAG potential, but this may not be possible in a timely fashion. The regulations should reflect these testing requirements. Final disposal must include adequate encapsulation to assure neutralization in perpetuity. It must also include adequate monitoring to assure that ARD does not leach into the underlying groundwater. A mitigation plan must be in place to remediate any disposal sites that do leak ARD.

COMMENTS ON SPECIFIC PROPOSED REGULATIONS

The proposed regulations increase the overlap lengths for cement plugs in abandoned O&G wells from 15 to 50 feet at several locations (6 NYCRR§ 555.5(a)). This increase in plug length is an improvement but not sufficient or well planned in all locations. Rather than filling "with

cement from total depth to at least 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity" (6 NYCRR§ 555.5(a)(1)), the regulation requiring cementing to 50 feet above the top of the shallowest formation in which gas has been observed; not all gas pockets have actually produced gas but could cause methane contamination if they are not already sealed off by casing. The regulations should specify that the cement plug "below the deepest potable fresh water level" should overlap the transition than be just below it because even a short section of uncased well bore open to the salt water could mix into the well and to above the fresh water line (6 NYCRR§ 555.5(a)(3)).

The definition of "public water supply" (6NYCRR§ 560.2(19)) appears to include only groundwater by referring to "a…well system which provides piped water". However, the definition of "reservoir" (6NYCRR§ 560.2(20)) includes "waterbody designated for use as a dedicated public water supply". The regulations must clear up this inconsistency by making clear that a "public water supply" includes ground- and surface water.

Operators must include in their applications various items (6NYCRR§ 560.3). The following address some of these requirements by number (the setback requirements were addressed above in the section concerning setbacks).

(2): The estimated maximum depth and elevation of bottom of potential freshwater: The operator should also be required to complete geophysical logging including conductivity measurements to verify the depth, unless it had been based on "previous drilling on the well pad".

(3): The "proposed volume of water to be used in hydraulic fracturing": The operator should also be required to discuss and specify how the estimated volume was determined.

(5), (6): The two parts specify that the application will provide the distance to various features but only if they are within a given specific distance. With current geographic information systems technology, there is no difficulty in obtaining these distances. The application should provide the distance to the water supply features in (5) and the aquifer and stream features in (6) if they are within two miles.

Mapping requirements for the application are specified in 6 NYCCR § 560.3(b). The topographic map requirements (6 NYCCR § 560.3(b)(2) require essentially a site map within 2640 feet of the proposed surface location (RDSGEIS, p. 3-9). This should be increased to 1 mile from the site, so that the map would be two by two miles centered on the proposed well pad. The map should include locations of all aquifers, water wells, stream channels, and other water features. The map should also include surface geology including faults. If fractures dominate the surface bedrock, contaminants can move quickly to wells. Contaminant pathways for transport from

the pad should be identified on the map. Contaminants would not move far upgradient, so the NYSDEC should focus downgradient. The following recommendations should be included in regulations regarding the requirements of well drillers to take steps to protect nearby wells.

- *The operator should complete site specific geology/hydrogeology studies to map the potential flow paths for contaminants released from the well pad or the well bore.*
- *All wells within a five-year transport zone should be located and included in sampling plans discussed below. Additionally, dedicated monitoring wells should be established within this zone, also as described below.*

The regulations require the operator to record and report the depths and flow rates where "freshwater, brine, oil and/or gas were encountered or circulation was lost during drilling operations" (6 NYCCR 560.6(c)(22)). The operator should identify these areas with specific conductivity logging. The regulations do not specify any limits or actions that the operator should take if certain flow or losses were recorded; they do not specify what the department will do with this information.

The required treatment plan "must include a profile showing anticipated pressures and volumes of fluid for pumping the first stage" (6 NYCCR 560.6(c)(22)). The operator also "must make and maintain a complete record of it hydraulic fracturing operation including the flowback phase" (6 NYCCR 560.6(c)(26)viii). The operator should compare the "anticipated pressures and volumes" with the actual values.

The operator must suspend operations immediately "if any anomalous pressure and/or flow conditions is indicated or occurring which is a significant deviation from either the treatment plan" (6 NYCCR 560.6(c)(26)vii). This is good, but the regulations do not define anomalous or what a significant deviation from the treatment plan would be, or what the follow-up action would be to assess and remedy damages.

Also, the required record of the fracking operation, 6 NYCCR 560.6(c)(26)viii, includes rates, volumes, and pressures of all injected and flowback fluids to the well. The department only requires a synopsis be provided to the department. There is no description what a synopsis should include. Instead, the department should require the full record be provided to the department, and this record should be made publically available online.

The regulations allow a well owner to waive setback requirements (6NYCRR§ 560.4(a)(1)). This should not be allowed unless there is also a requirement to inform potential purchasers of the well in the future of the waiver.

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APPENDIX A

Review of Appendix 11, Excerpt from ICF Report, Task 1, 2009

Analysis of Subsurface Mobility of Fracturing Fluids

Agreement No. 9679

Reviewed by

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December 7, 2009

Revised: November 14, 2011

Introduction

The New York State Energy and Development Authority (NYSERDA) contracted with ICF International to prepare a review of the hydraulic fracturing process as it will likely be applied to the Marcellus Shale in New York; this review was published as a supporting document for the 2009 RDSGEIS prepared by the New York State Department of Environmental Conservation. For the 2011 RDSGEIS, Appendix 11 presents excerpts from that report regarding the subsurface mobility of fracturing fluids. This is a review of Appendix 11, revised from a review completed by this author of the ICF International report contained in the 2009 RDSGEIS.

In summary, ICF completed an analysis of the potential for contamination to flow from the shale to freshwater aquifers, but misrepresented the actual situation in many ways. The basic problem was they conceptualized the flow potential incorrectly. They considered the gradient incorrectly and assumed that if the transport did not occur within the time period of fracturing, it would not occur. They assumed that the fluids leaving the shale would completely disperse, and be diluted, by occupying and being retained in every pore between the shale and the aquifers. They did not consider preexisting fractures. They ignored any potential pre-existing vertical gradient which would drive contaminants leaving the shale to the aquifers. Although they presented a geochemical analysis which could explain why some attenuation could occur, they provided no site specific or fluid specific data to indicate that it would occur.

Exposure Pathways

ICF analyzes the potential for fracturing fluid to flow from the shale to the freshwater aquifers anywhere from 1000 to 5000 feet above. The first problem is that the potential contaminants are both fracturing fluid and connate (formation) water existing in the shale before fracturing, which could contain extremely high concentrations of TDS, benzene, or radioactive materials. Therefore, ICF should have considered the potential for flow of both fracturing fluid and connate water. Ambient water could both be pushed from the shale by the injection of fracturing fluid and just by the opening of the pore spaces which would increase the permeability and allow more of a natural connection.

ICF calculates the gradient between the fracture zone and the bottom of the freshwater zone, which they set at 1000 feet bgs to be conservative in because much of the groundwater below this level in southern New York is not an underground source of drinking water either because it is too salty or the formation is not sufficiently productive to be considered an aquifer. However, their calculation applied only during the period of injection. Myers (in review) demonstrated through modeling that the fracking pressure would dissipate over a period of months, not immediately after fracking ended, because of the fluid that has been pushed away from the well. The effective gradient is from the well to just beyond the migrating fluid where pressures would not yet have been affected by the current fracking.

ICF also ignores the potential for a natural upward gradient, which could be due to natural artesian pressure. Myers (in review) also discusses the potential for this in detail.

ICF properly calculated the pressure that would occur in the shale during fracturing based on the effective stress in the formation and the amount of pressure required to overcome the in-situ horizontal stress (ICF, pages 25-26); accepting the assumptions in the following quote, equation 12, and equations 7 through 11 used to derive it, is an accurate description of the head applied to the shale during fracturing.

> Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of the geologic materials (estimated at 150 pcf average), times the depth. To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress… (ICF, pages 25-26)

ICF uses that equation with the gradient equation 6 to estimate the gradient between the shale and freshwater aquifer, “during hydraulic fracturing”, for a variety of depths of the aquifer and the shale. The numbers are correct, for an aquifer depth of 1000 feet and shale depth of 2000 feet, they show the gradient to be about 3.6, but the concept applied in the derivation is wrong as described above. During hydraulic fracturing, variously estimated through the RDSGEIS

documents as occurring for up to 5 days, there is no hydraulic connection between the shale and the bottom of the freshwater aquifer and it is therefore inappropriate to consider the gradient across that thickness. The correct conceptualization is described in the following paragraph.

Upon applying a pressure in the shale, as occurs during the injection for fracturing, a very high pressure head is developed at the well and nearby shale. This pressure causes the gradient that drives the fluid away from the well into the shale, where it causes the shale to fracture. Fluid may continue to flow into surrounding formations. During the process, the pressure begins to increase away from the well which establishes a steep gradient near the well. Away from the well at any given time during injection, the pressure is less than at the well. The pressure drop from the well to any point in the shale away from the well is a function of the friction incurred by the fluid flowing away from the well. At some distance from the well, the pressure is only at background. The distance at which the pressure is only background is the point at which the injection fluid has not yet reached. Beyond the point to which the injection fluid flows, there is NO hydraulic connection. For this reason, ICF's calculation for gradient between the injection pressure in the shale and the bottom of the freshwater aquifer is hydrogeologically incorrect. ICF is effectively analyzing a steady state situation that would occur if the injection pressure continued until the pressure stabilized between the shale and the freshwater aquifer.

ICF acknowledges the reality that transient or non-steady conditions will prevail and that the actual pressure gradient will be higher closer to the shale. "In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer to the fracture zone and lower than the average closer to the aquifer." (ICF, pages 26-27)

However, they do not carry the analysis any further and seem to argue that immediately after injection ceases, all upward gradient will cease: "It is important to note that these gradients only apply while fracturing pressures are being applied. Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer" (ICF, page 27). The implication from this statement is that ending injection will cause the pressure in the reservoir to drop back to background, immediately. This is not possible, any more than it is possible for the drawdown in a pumping well in an aquifer to return to pre-pumping conditions immediately upon cessation of pumping.

For example, consider that during a five-day injection period, the pressure propagated outward from the well as described in Myers (in review). When injection ends, the pressure within the well may almost immediately return to background, but the pressure in the surrounding formation will still be very high. This is the pressure which will drive the flowback to the well, as described throughout the RDSGEIS. The initial flowback is fluid right next to the well – the

fluid that had just been injected. The pressure field created in the formation away from the well is the pressure that causes a gradient to push the fluid back into the well.

As long as there is flowback, there is a gradient toward the well, and residual pressure in the shale or surrounding formations. With distance from the well, the pressure increases (as required for there to be a gradient back to the well). At any given time, there will be a point of maximum pressure beyond which the pressure becomes lower; in other words, a cross-section through the formation away from the well showing the pressure head would show the pressure rising from the well to the peak and falling from the peak to the point the pressure reaches background. (This is similar to the concept in hydrogeology that during pumping, the maximum drawdown caused by a well is at the well; when the well ceases to pump, the water level will initially rise quickly, but the drawdown away from the well will continue to expand for a period of time.)

ICF considers that local drawdown caused by production from the well will further prevent flow away from the well: "During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow" (ICF, page 27). This is probably correct, but the process described in the preceding paragraph likely causes some of the fluid to have moved beyond this propagating drawdown. The fact that only 35% of the injected fluid returns as flowback (RDSGEIS, Gaudlip et al, 2008) would seem to confirm that much of the injected fluid gets beyond the point where the reversing gradient would pull the fluid back to the well.

ICF also relies on there being no connection between the shale and surrounding formations, as indicated by the high TDS content of water in the shale. This may reflect the pre-fractured conditions, but the fracturing process could open a connection between formations. As noted in the main body of this review, out-of-zone fracking is not uncommon, therefore it is reasonable to assume that connections between the shale and surrounding formations do occasionally occur.

The analysis provided by ICF in section 1.2.4.3, Seepage Velocity, is irrelevant because it considers the velocity between the shale and the freshwater aquifer, using a gradient established in the previous section that only applies for as long as the injection. Their calculation of 10 ft/day (ICF, page 28) relies on that average gradient. They seem to acknowledge the fallacy of their assumptions by stating: "The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata" (ICF, page 28, emphasis added). ICF carries the error into section 1.2.4.4, Required Travel Time, by calculating how long it would take for flow at the seepage velocity calculated in the previous section to reach the freshwater aquifers.

ICF's fourth argument is that even if all of the injected fluid moves vertically out of the shale towards the freshwater aquifer, it would have to disperse among all of the pores between the shale and the aquifer – a truly nonsensical idea. The calculation requires that 4,000,000 gallons of fluid would be evenly dispersed throughout a 40-acre well spacing. In other words, they assume that about 4,000,000 gallons of injected fluid would evenly disperse through all of the void, assuming porosity of 0.1, over a 1000-foot thickness 40 acres in area, or about 1.3 billion gallons of void space, would cause a dilution factor of 300 (ICF, pages 30-31). This is wrong for the following reasons.

- An injected fluid would move as a slug along the gradient. In this case, with a natural upward gradient, any fluid that escapes the well bore (does not flowback) would disperse upward. It would not diffuse through every pore space between the shale and aquifer. Advective forces would move it upward as a slug with dispersion spreading it out both vertically and horizontally. It will dilute, but far less than postulated by ICF's analysis.
- The vertical flow would follow preferential flow paths rather than advecting upwards uniformly across 40 acres. The image painted by ICF is that the fluid would flow upward to the aquifer with the leading edge moving at exactly the same rate over the entire area. Even if there are no fractures, faults, or improperly plugged wells, simple finger flow, caused by heterogeneities in the material properties, would cause an uneven distribution of the contaminant.

ICF also rejects the concept of fractures, faults, or unplugged wells by claiming it is "extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer" (ICF, page 31). They provide no data or references to assess the probability that such a network is "extremely unlikely" or to justify their conclusion. More importantly, for fractures to facilitate a connection between the shale and the aquifers, it is not necessary for the fracture to exist over the entire thickness. As ICF (page 5) mentions, the Marcellus Shale has substantial natural fractures, and therefore it is possible that the surrounding formations, sandstone or shale, also have fractures. It is not necessary for the flow to follow a fracture all the way to the aquifers, but it could enhance the velocity of movement. Fractures could also further disperse the flow vertically, as discussed in Myers (in review).

ICF also mentions geochemistry as a reason that transport of contaminants from the shale to the aquifers will not occur. While it is possible for attenuation to occur as contaminants move through a formation, without site specific and chemical specific data, they should not make such an argument.

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APPENDIX B

Prepublication Copy

Myers, T., in review. POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

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ABSTRACT

Hydraulic fracturing (fracking) of deep shale beds to develop natural gas has caused concern regarding the potential for various forms of water pollution. Two potential pathways – diffuse transport through bulk media and preferential flow through fractures – could allow the transport of contaminants from the fractured shale to aquifers. There is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep evaporite sources. Interpretative numerical modeling shows that diffuse transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 liters of fluid into the shale generates high pressure at the well which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media and widens existing fractures. Simulated pressure returns to pre-injection levels in about 90 days. The overall system requires from three to six years to reach a new equilibrium reflecting the significant changes caused by fracking the shale. The rapid expansion of hydraulic fracturing requires that monitoring systems be employed to track the movement of contaminants and that gas wells have a reasonable offset from faults.

Introduction

The use of natural gas (NG) in the United States has been increasing, with 53 percent of new electricity generating capacity between 2007 and 2030 projected to be with NG-fired plants (EIA 2009). Unconventional sources account for a significant proportion of the new NG available to the plants. A specific unconventional source has been deep shale-bed NG, including the Marcellus shale primarily in New York, Pennsylvania, Ohio, and West Virginia (Soeder 2010), which has seen over 4000 wells developed between 2009 and 2010 in Pennsylvania (Figure 1).Unconventional shale-bed NG differs from conventional sources in that the permeability is so low that gas does not naturally flow in timeframes suitable for development. Hydraulic fracturing (fracking, the industry term for the operation (Kramer 2011)) loosens the formation to release the gas and provide pathways for it to move to a well.

Fracking injects 13 to 19 million liters of fluid consisting of water and additives, including benzene at concentrations up to 560 ppm (Jehn 2010), at pressures up to 69,000 kPa (PADEP 2011) into low permeability shale to force open and connect the fractures. This is often done using horizontal drilling through the middle of the shale. Horizontal wells may be more than a kilometer (km) long. The amount of injected fluid that returns to the ground surface after fracking ranges from 9 to 34 percent of the injected fluid (Alleman 2011; NYSDEC 2009), although some would be formation water.

Many agency violation reports and legal citations (ODNR 2008; PADEP 2009) and peer-reviewed articles (DiGuilio et al. 2011; Osborn et al. 2011; Breen et al. 2007; White and Mathes 2006) have found more gas in water wells near areas being developed for unconventional NG, documenting the source can be difficult. One reason for the difficulty is the different sources – thermogenic for gas formed by compression and heat at depth in shale and bacteriogenic for gas formed by bacteria breaking down organic material (Schoell 1980). The source can be distinguished based on both C and H isotopes and the ratio of methane to higher chain gases (Osborn and McIntosh 2010; Breen et al 2007). Thermogenic

gas can reach aquifers only by leaking from the well bore or by seeping vertically from the source. In either case, the gas must flow through potentially very thick sequences of sedimentary rock to reach the aquifers. Many studies which have found thermogenic gas in water wells found there to be more gas near fracture zones (DiGuilio et al. 2011; Osborn et al. 2011; Thyne 2008; Breen et al. 2007), suggesting that fractures are pathways for gas to move from shale or other deep formations to aquifers.

A pathway for gas would also be a pathway for fluids and contaminants to advect from the fractured shale to the surface, although the time for transport would likely be longer. Two reports (DiGuilio et al. 2011; EPA, 1987) have documented the presence of fracking fluid in aquifers and another found elevated chloride (Thyne 2008), linked to fracking, in wells, although the exact source and pathways had not been determined.

There is sufficient documented gas movement and circumstantial evidence regarding fluids movement to suggest that there is a potential for fracking fluid or shale-bed formation fluid to reach aquifers. With the vastly increasing development of unconventional NG sources, the risk to aquifers could seemingly be increasing. However, there is almost no data concerning the movement of contaminants along pathways from depth, either from wellbores or from deep formations, to aquifers. The only way in the short term to explore the risk is with conceptual analyses.

To consider the potential transport from depth to aquifers, I have considered first the potential pathways for contaminant transport through bedrock between deep shale and surface aquifers, and the necessary conditions for such transport to occur. Second, I have estimated contaminant travel times through the potential pathways, with a bound on these estimates based on formation hydrologic parameters, using interpretative MODFLOW-2000 computations. The modeling does not, and cannot, account for all of the complexities of the geology, which could either increase or decrease the travel

times compared to those considered herein. The intent of this study is to characterize the risk factors, so the modeling is used, similar to that by Hsieh (2011), to consider the possibilities.

The Marcellus shale area of northern Pennsylvania and southern New York is the study area (Figure 1), although the concepts should apply anywhere there is a deep unconventional NG source separated from the surface by sedimentary rock.

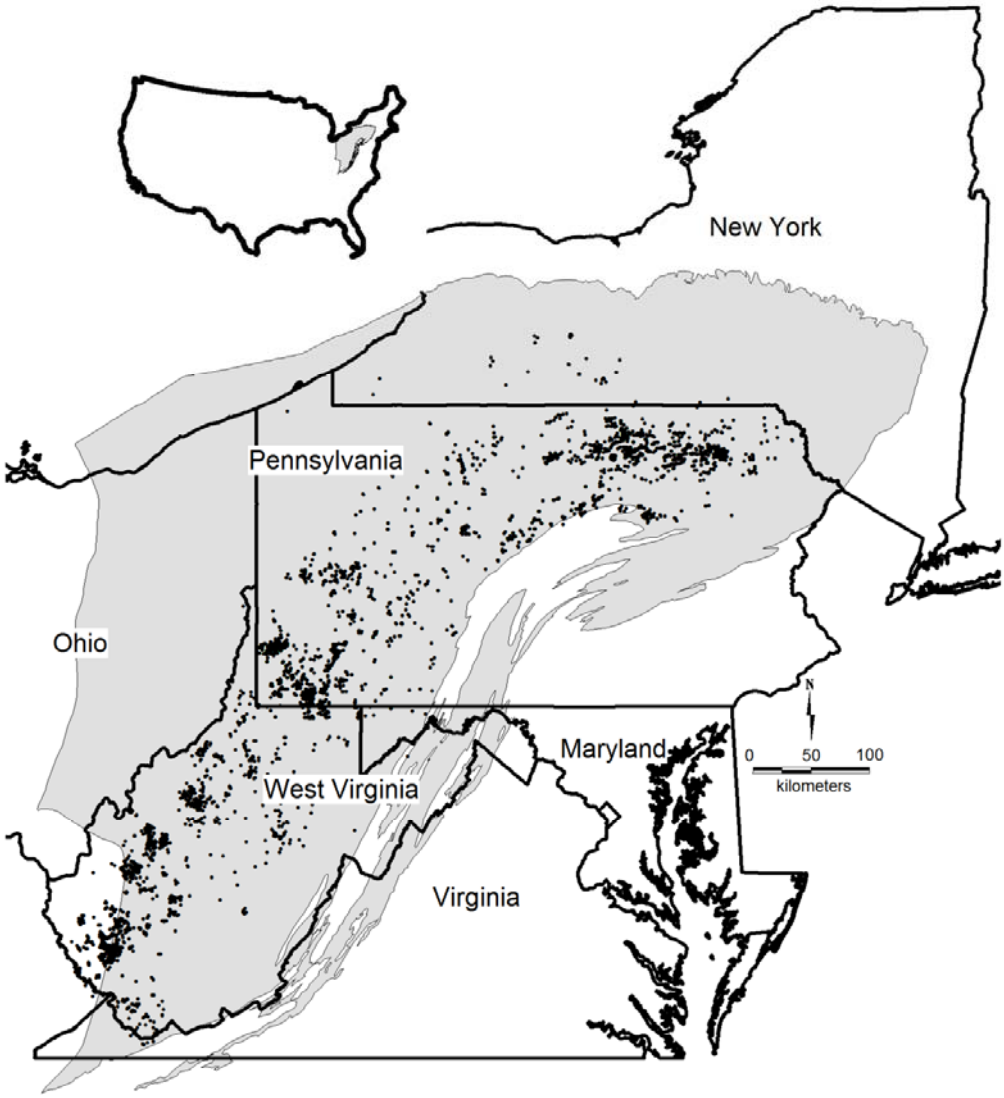


Figure 2: Location of Marcellus shale in northeastern United States. Location of Marcellus wells (dots) drilled July 2009 to June 2010 and total Marcellus shale wells in New York and West Virginia. There are 4064 wells shown in Pennsylvania, 48 wells in New York, and 1421 wells in West Virginia. Faulting in the area may be found in PBTGS (2001), Isachsen and McKendree (1977), and WVGES (2011, 2010a and 2010b).

Method of Analysis

I consider several potential scenarios of transport from shale, 1500 m below ground surface to the surface, beginning with pre-development steady state conditions to establish a baseline and then scenarios considering transport after fracking has potentially caused contaminants to reach the overlying formations. To develop the conceptual models and MODFLOW-2000 simulations, it is necessary first to consider the hydrogeology of the shale and the details of hydraulic fracturing, including details of how fracking changes the shale hydrogeologic properties.

Hydrogeology of Marcellus Shale

Shale is a mudstone, a sedimentary rock consisting primarily of clay- and silt-sized particles, which tend to break in one direction (Nichols 2009). It forms through the deposition of fine particles in a low energy environment, such as a lake- or seabed. The Marcellus shale formed in very deep offshore conditions during Devonian time (Harper 1999) where only the finest particles had remained suspended. Because sufficient organic matter settled with the clay and silt, anaerobic decomposition caused the formation of methane. The depth to the Marcellus shale varies to as much as 3000 m in parts of Pennsylvania, and averages about 1500 m in southern New York. Between the shale and the ground surface are layers of sedimentary rock, including sandstone, siltstone, and shale (NYSDEC 2011).

Marcellus shale has very low natural intrinsic permeability, on the order of 10^{-16} Darcies (Kwon et al. 2004a and 2004b; Neuzil 1994 and 1986), which makes it an extremely efficient seal, or capstone, for keeping natural gas in underlying sandstone. At a gradient equal to 1 with an intrinsic permeability equal to $100x10^{-9}$ darcies, water would flow only 0.000025 m in a year.

Schulze-Makuch et al. (1999) described Devonian Shale of the Appalachian Basin, of which the Marcellus is a major part, as containing “coaly organic material and appear either gray or black” and being “composed mainly of tiny quartz grains < 0.005 mm diameter with sheets of thin clay flakes”. Median

particle size is 0.0069±0.00141 mm with a grain size distribution of <2% sand, 73% silt, and 25% clay. Primary pores are typically 5 x 10^{-5} mm in diameter, matrix porosity is typically 1% to 4.5% and fracture porosity is typically 0.078 to 0.09% (Schulze-Makuch et al. 1999 and references therein).

The Marcellus shale is fractured by faulting and contains synclines and anticlines which cause tension cracks (Engelder et al. 2009; Nickelsen 1986). It is sufficiently fractured in some places to support water wells just six to ten km from where it is being developed for NG at 2000 m below ground surface (bgs) in eastern Lycoming County, Pennsylvania (Lloyd and Carswell 1981) (Figure 2).

Porous flow in unfractured shale is negligible due to the low bulk media permeability, but at larger scales the fractures control and may allow significant flow. Conductivity scale dependency (Schulze-Makuch et al.1999) may be described as follows:

$$K = Cv^m$$

K is hydraulic conductivity (m/s), C is the intercept of a log-log plot of observed K to scale (the K at a sample volume of 1 m^3), V is sample volume (m^3), and m is a scaling exponent determined with log-log regression; for Devonian shale, C equals -14.3 and m equals 1.08 (Schulze-Makuch et al. 1999). Most of their samples were small because the deep shale is not easily tested at a field-scale and no groundwater models have calibrated for flow through the Marcellus shale, therefore field scale K estimates are uncertain. Considering a 1 km square area with 30 m thickness, the Kh would equal 5.96x10^{-7} m/s (0.0515 m/d). This effective K is low and the shale would be an aquitard, but a leaky one.

Contaminant Pathways from Shale to the Surface

Three studies (Osborn et al. 2011; Thyne 2008; Breen et al. 2007) have found gas in near-surface water wells and suggested that the most likely cause was vertical transport of gas from depth, possibly linked to the presence of faults through which the gas could flow. Osborn et al. (2011) found systematic

circumstantial evidence for higher methane concentrations in wells within 1 km of Marcellus shale gas wells that had been fracked. Gas moves through fractures depending their width (Etiope and Martinelli 2001) and is a primary concern for many projects, including carbon sequestration (Annunziatellis et al. 2008) and natural gas storage projects (Breen et al. 2007).

Pathways for gas suggest pathways for fluids and contaminants, if there is a gradient. Vertical hydraulic gradients of a up to a few percent, or about 30 m over 1500 m, exist throughout the Marcellus shale region as may be seen in various geothermal developments in New York (TAL 1981). Brine more than a thousand meters above their evaporite source (Dresel and Rose 2010) is evidence of upward movement of contaminants from depth to the surface. The Marcellus shale, with salinity as high as 350,000 mg/l (Soeder 2010; NYDEC 2009), may be a primary brine source. Relatively uniform brine concentrations over large areas (Williams et al. 1998) suggest widespread diffuse transport, which would occur if there is a sufficient concentration gradient. The transition from briny to freshwater suggests a long-term equilibrium between the upward movement of brine and downward movement of freshwater.

Faults, which occur throughout the Marcellus shale region (Gold 1999), could provide pathways (Caine et al. 1996; Konikow 2011) for more concentrated advective and dispersive transport. Brine concentrating in faults or anticline zones reflects potential preferential pathways (Wunsch 2011; Dresel and Rose 2010; Williams 2010; Williams et al. 1998).

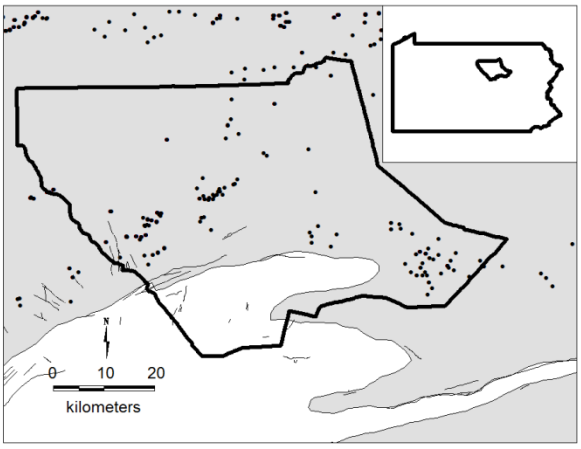


Figure 3: Marcellus shale wells and the Marcellus outcrop in Lycoming County, Pennsylvania. The grey shading is the area of Marcellus shale, which outcrops along its boundary along an area about 1 km wide (Lloyd and Carswell 1981). Faults from PBTGS (2001).

Effect of Hydraulic Fracturing on Shale

Fracking increases the permeability of the targeted shale to make extraction of natural gas economically efficient (Engelder et al. 2009; Arthur et al. 2008). Fracking creates fracture pathways with up to 9.2 million square meters of surface area in the shale accessible to a horizontal well (King 2010; King et al. 2008) and connects natural fractures (Engelder et al. 2009; King et al. 2008). No post-fracking studies that documented hydrologic properties such as conductivity were found while researching this article (there is a lack of information about pre- and post-fracking properties (Schweitzer and Bilgesu 2009)), but it is reasonable to assume the K increases significantly because of the newly created and widened fractures.

Fully developed shale typically has wells spaced at about 300-m intervals (Krissane and Weissert 2011; Soeder 2010). Up to eight wells may be drilled from a single well pad (NYDEC 2009; Arthur et al. 2008), although not in a perfect spoke pattern. Reducing by half the effective spacing did not enhance overall productivity (Krissane and Weissert 2011) which indicates that 300–m spacing creates sufficient overlap among fractured zones to assure adequate gas drainage. The properties controlling groundwater flow

would therefore be affected over a large area, not just at a single horizontal well or set of wells emanating from a single well pad.

Fracking is not intended to affect surrounding formations, but shale properties vary over short ranges (King 2010; Boyer et al. 2006) and out of formation fracking is not uncommon. Fluids could reach surrounding formations just because of the volume injected into the shale, which must displace natural fluid, such as the existing brine in the shale. For example, if 15 million liters is injected into shale over a 1000 m long horizontal well, the fluid could occupy all of the pore spaces within 7 to 16 m from the well for effective porosity ranging from 0.1 to 0.02. Even with 20% of the fluid returning to the well, a significant amount of existing pore space would be occupied by the injected fluid, displacing the existing brine and gas.

Analysis of Potential Transport along Pathways

Fracking could cause contaminant to reach overlying formations either by fracking out of formation, connecting fractures in the shale to overlying bedrock, or by simple displacement of fluids from the shale into the overburden. Advective transport will manifest if there is a significant vertical component to the regional hydraulic gradient. Advective transport can be considered with the simple particle velocity determined with Darcy velocity and effective porosity.

Numerical modeling provides flexibility to consider potential conceptual flow scenarios, but should be considered interpretative (Hill and Tiedeman, 2007). Numerical simulation presented herein was completed with the MODFLOW-2000 code (Harbaugh et al. 2000). The simulation considers the rate of vertical transport of contaminants to near the surface for the different conceptual models, based on an expected, simplified, realistic range of hydrogeologic aquifer parameters.

MODFLOW-2000 is a versatile numerical modeling code, but it is not perfect for all of the factors required for this simulation. The native water at depth near the shale is brine, much saltier than seawater, therefore the injected fluid would be lighter so buoyancy factors may speed the upward flux beyond the simple consideration of hydraulic gradient. As more data becomes available, it may be useful to consider the added upward force caused by the brine by using the SEAWAT-2000 module (Langevin et al. 2003).

Vertical flow would be perpendicular to the general tendency for sedimentary layers to have higher horizontal than vertical conductivity. Fractures and improperly abandoned wells would provide pathways for much quicker vertical transport than general advective transport. This paper considers the fractures as vertical columns with cells having much higher conductivity than the surrounding bedrock. The cell discretization is fine, so the simulated width of the fracture zones is realistic. Dual porosity modeling would not be useful because high velocity vertical flow through the fractures is unlikely. MODFLOW-2000 has a module, MNW (Halford and Hansen 2002), that could simulate flow through open bore holes. Open boreholes would clearly provide rapid transport if the head deep in the borehole exceeds that near the surface or if fractures containing fracking fluid intersect or come close to the borehole. Because it is possible to simply plug open boreholes, I have limited consideration here to fractures; however, models of well fields should include known boreholes.

The thickness of the formations and fault would affect the simulation, but much less than the several-order-of-magnitude variation possible in the shale properties. The overburden and shale thickness were set equal to 1500 and 30 m, respectively, similar to that observed in southern New York. The estimated travel times are proportional for thicker or thinner sections. The overburden could be predominantly sandstone, sections of shale, mudstone, and limestone could exert local control. The vertical fault is assumed to be 6 m thick.

There are five conceptual models of flow and transport of natural and post-fracking transport from the level of the Marcellus shale to the near-surface to consider with an interpretative numerical model.

1. The natural upward diffuse flow due to a head drop of 30 m from below the Marcellus shale to the ground surface, considering the variability in both shale and overburden K. This is a steady state solution for upward advection through a 30-m thick shale zone and 1500-m overburden and is a baseline condition for upward flow through unfractured sedimentary rock.
2. Same as number 1, but with a fracture zone connecting level of the shale with the surface. This emulates the conceptual model postulated for flow into the alluvial aquifers near stream channels, the location of which may be controlled by faults (Williams et al 1998). The fault K varies from 10 to 1000 times the surrounding bulk sandstone K.
3. This scenario tests the effect of extensive fracturing in the Marcellus shale by increasing the shale K from 10 to 1000 times its native value over an extensive area. This transient solution starts with initial conditions being a steady state solution from scenario 1. The K in the shale layers increases from 10 to 1000 times at the beginning of the simulation, to represent the relatively instantaneous change on the regional shale hydrogeology imposed by the fracking. This scenario estimates both the changes in flux and the time for the system to come to equilibrium after fracking.
4. As number 3, considering the effect of the same changes in shale properties but with a fault as in number 2.
5. This scenario simulates the actual injection of 13 to 17 million liters of fluid in five days into fractured shale from a horizontal well with and without a fault.

Model Setup

The model domain was 150 rows and columns spaced at 3 m to form a 450 m square (Figure 3) with 50 layers bounded with no flow boundaries. The 30-m thick shale was divided into 10 equal thickness layers from layer 40 to 49. The overburden layer thickness varied from 3 m just above the shale to layer 34, 6 m layer 29, 9 m to layer 26, 18 m in layer 25, 30 m to layer 17, 60 m to layer 6, 90 m to layer 3, and 100 m in layers 2 and 1

The model simulated vertical flow between constant head boundaries in layers 50 and 1, as a source and sink, so that the overburden and shale properties control the flow. The head in layers 50 and 1 was 1580 and 1550 m, respectively, to create an upward gradient of 0.019 over the profile. Varying the gradient would have much less effect on transport than changing K over several orders of magnitude and was therefore not done.

This simulation considers particle travel times between the top of the shale and the top of the model domain based on an effective porosity of 0.1. A 6-m wide fault is added for some scenarios in the center two rows from just above the shale, layer 39 to the surface. The fault is an attempt at considering fracture flow, but the simulation treats the six meter wide fault zone as homogeneous, which could underestimate the real transport rate in fracture-controlled systems. The simulation also ignores diffusion between the fracture and the adjacent shale matrix (Konikow, 2011).

Scenario 5 simulates injection using a WELL boundary in layer 44, essentially the middle of the shale, from columns 25 to 125 (Figure 3). It injects 15 million liters over one 5-day stress period, or 3030 m^3/d into 101 model cells at the WELL. The modeled shale K was changed to its assumed fracked value at the beginning of the simulation. Simulating high rate injection generates very high heads in the model domain, similar to that found simulating oil discharging from the well in the Deepwater Horizon crisis (Hsieh, 2011) and water quality changes caused by underground coal gasification (Contractor and El-

Didy 1989). DRAIN boundaries on both sides of the WELL simulated return flow for sixty days after the completion of (Figure 3), after which the DRAIN was deactivated. The sixty days were broken into four stress periods, 1, 3, 6, and 50 days long, to simulate the changing heads and flow rates. DRAIN conductance was calibrated so that 20% of the injected volume returned within 60 days to emulate standard industry practice (Alleman 2008; NYSDEC 2009). Recovery, continuing relaxation of the head at the well and the adjustment of the head distribution around the domain, occurred during the sixth period which lasted for 36,500 days, a length of time that simulation of scenarios 3 and 4 indicated would suffice.

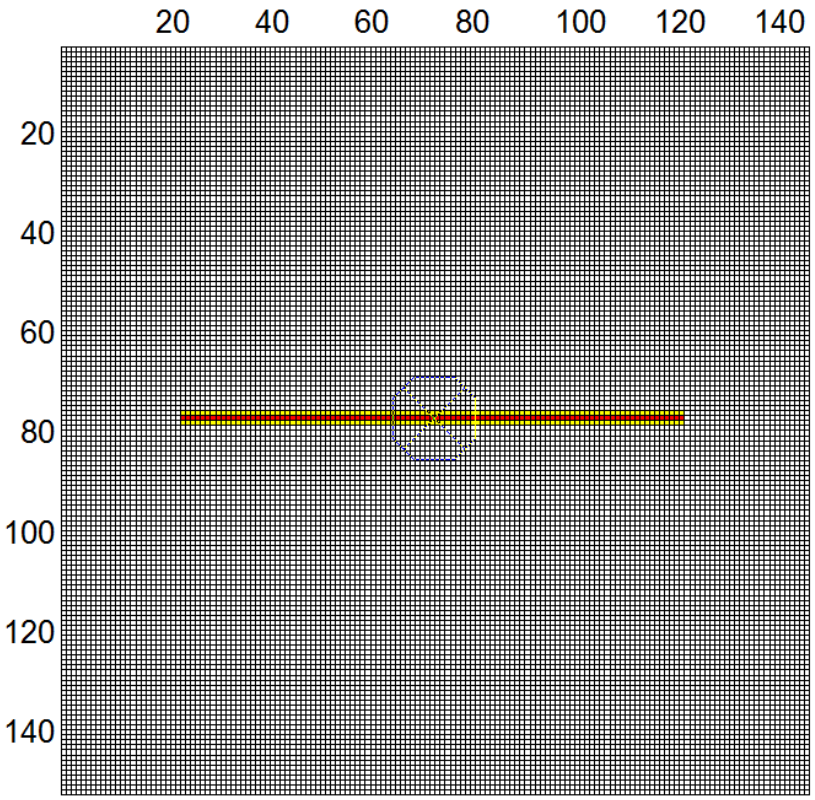


Figure 4: Model grid through layer 44 showing the horizontal injection WELL (red) and DRAIN cells (yellow) used to simulate flowback. The figure also shows the monitoring well.

There is no literature guidance to a preferred value for fractured shale storage coefficient, so I estimated S with a sensitivity analysis using scenario 3. With fractured shale K equal to 0.001m/d, two orders of magnitude higher than the in-situ value, the time to equilibrium resulting from simulation tests of three fractured shale storage coefficients, 10^{-3}, 10^{-5}, and 10^{-7} m^{-1}, varied twofold (Figure 4). The slowest time to equilibrium was for S=10^{-3} m^{-1} (Figure 4), which was chosen for the transient simulations because more water would be stored in the shale and flow above the shale would change the least.

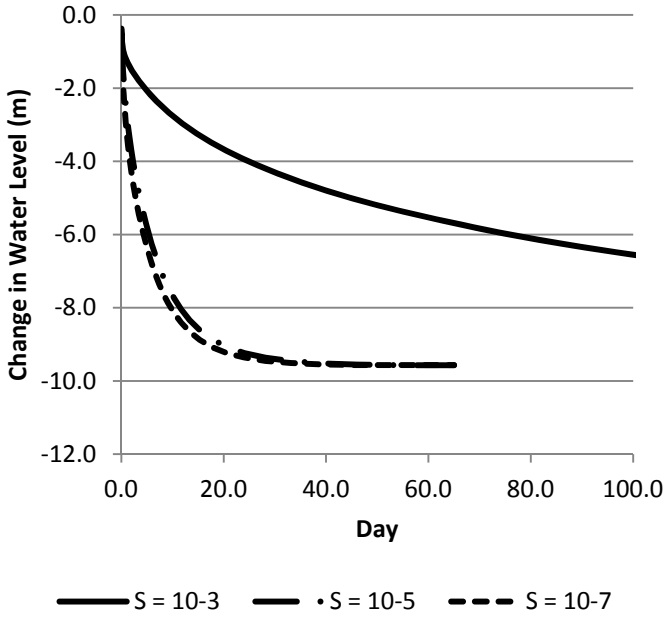


Figure 5: Sensitivity of the modeled head response to the storage coefficient used in the fractured shale for model layer 39 just above the shale.

Results

Scenario 1

The travel time for a particle to transport through 1500 m of sandstone and shale equilibrates with one of the formations controlling advection (Figure 5). For example, when the shale K equals 1x10^{-5} m/d, transport time does not vary with sandstone K. For sandstone K at 0.1 m/d, transport time for varying

shale K ranges from 40,000 years to 160 years. The lower travel time estimate is for shale K similar to that found by Schulze-Makuch et al. (1999). The shortest simulated transport time of about 20 years results from both the sandstone and shale K equaling 1 m/d. Other sensitivity scenarios emphasize the control exhibited by one of the media (Figure 5). If shale K is low, travel time is very long and not sensitive to sandstone K.

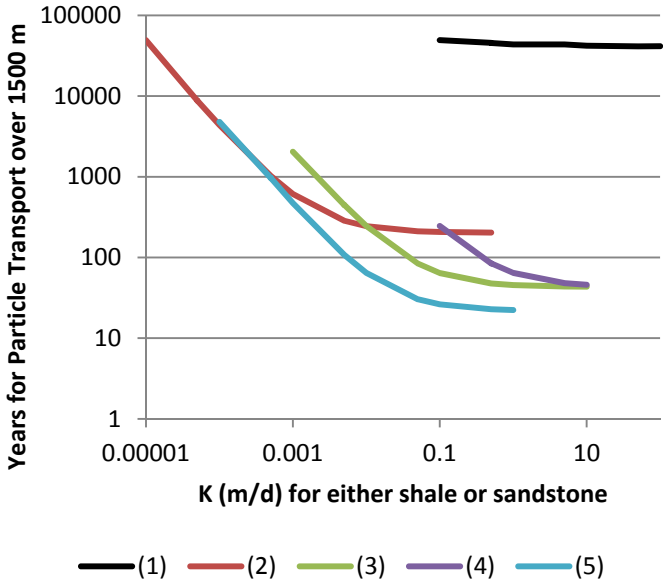


Figure 6: Sensitivity of particle transport time over 1500 m for varying shale and sandstone vertical K. Effective porosity equals 0.1. (1) – varying Kss, Ksh=10-5 m/d, (2) – varying Ksh, Kss= 0.1 m/d, (3) – varying Kss, Ksh = 0.1 m/d, (4): varying Kss, Ksh = 0.01 m/d, and (5): varying Ksh, Kss= 1.0 m/d.

Scenario 2

Vertical transport time through a system including a high-K fault zone was limited primarily by the shale K, presumably because the fault K was one to two orders of magnitude more conductive than that of the surrounding sandstone (Figure 6). Including a fault increased the particle travel rate by about 10 times (compare Figure 8 with Figure 6). The fault K controlled the transport rate for shale K less than 0.01 m/d. A highly conductive fault could transport fluids to the surface in as little as a year for shale K equal to 0.01 m/d (Figure 6).

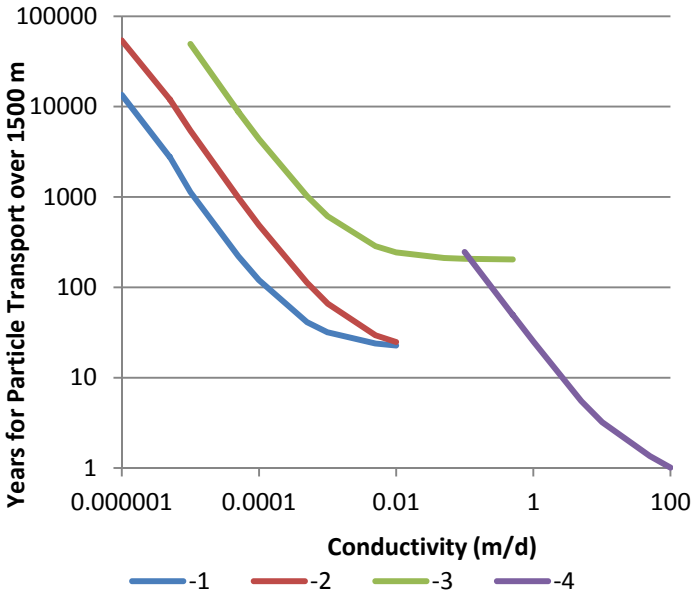


Figure 7: Variability of transport through various scenarios of changing the K for the fault or shale. Effective porosity equals 0.1. (1): Vary Ksh, Kss=0.01 m/d; (2): Varying Ksh, Kss=0.1 m/d; (3), no fault; (4): Varying K fault, Kss=0.1 m/d, Ksh=0.01 m/d. Unless specified, the vertical fault has K=1 m/d for variable shale K.

Scenarios 3 and 4

Scenarios 3 and 4 estimate the time to establish a new equilibrium for scenarios 1 and 2. Equilibrium times would vary by model layer as the changes propagate through the domain, and flux rate for the simulated changes imposed on natural background conditions. The fracking-induced changes cause a significant decrease in the head drop across the shale and the ultimate adjustment of the potentiometric surface to steady state depends on the new shale properties.

The time to equilibrium for one scenario 3 simulation, shale K changing from 10^{-5} to 10^{-2} m/d with sandstone K equal to 0.1 m/d, varied from 5.5 to 6.5 years, depending on model layer (Figure 7). Near the shale (layers 39 and 40), the potentiometric surface increased from 23 to 25 m reflecting the decreased head drop across the shale. One hundred meters higher in layer 20, the head increased about 20 m. These changes reflect the decrease in K across the shale. Simulation of scenario 4, with a fault with K=1 m/d, decreased the time to equilibrium to from 3 to 6 years within the fault zone,

depending on model layer (Figure 7). Faster transport occurred only in areas near the fault. Highly fractured sandstone would allow more vertical transport, but diffused advective flow would also increase so that the base sandstone K would control the overall rate.

The flux across the upper boundary changed within 100 years for scenario 3 from 1.7 to 345 m^3/d, or 0.000008 m/d to 0.0017 m/d. There is little difference in the equilibrium fluxes between scenario 3 and 4 indicating that the fault primarily affects the time to equilibrium rather than the long-term flow rate.

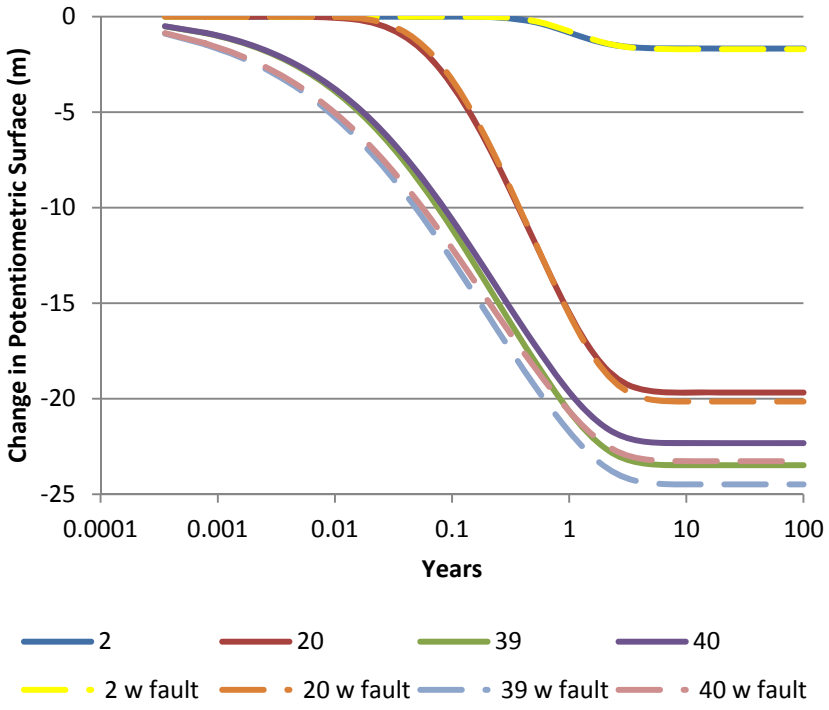


Figure 8: Monitoring well water levels for specified model layers due to fracking of the shale; monitor well in the center of the domain, including in the fault, K of the shale changes from 0.00001 to 0.01 m/d at the beginning of the simulation.

Scenario 5: Simulation of Injection

The injection scenarios simulate 15 million liters entering the domain at the horizontal well and the subsequent potentiometric surface and flux changes throughout. The highest potentiometric surface

increases (highest injection pressure) occurred at the end of injection (Figure 8), with a 2400 m mound at the horizontal well. The peak pressure simulated both decreased but occurred longer after the cessation of injection with distance from the well (Figure 8). The pressure at the well returned to within a meter of pre-injection levels in about 95 days (Figure 8). After injection ceases, the peak pressure simulated further from the well occurs longer from the time of cessation, which indicates there is a pressure divide beyond which fluid continues to flow away from the well bore while within which the fluid flows toward the well bore. The simulated head returned to near pre-injection levels slower with distance from the well (Figure 9), with levels at the edge of the shale (layer 40) and in the near-shale sandstone (layer 39) requiring several hundred days to recover. After recovering from injection, the potentiometric surface above the shale increased in response to flux through the shale adjusting to the change in shale properties (Figure 9), as simulated in scenario three. The scenario required about 6000 days (16 years) for the potentiometric surface to stabilize at new, higher, levels (Figure 9). Removing the fault from the simulation had little effect on the time to stabilization, and is not shown.

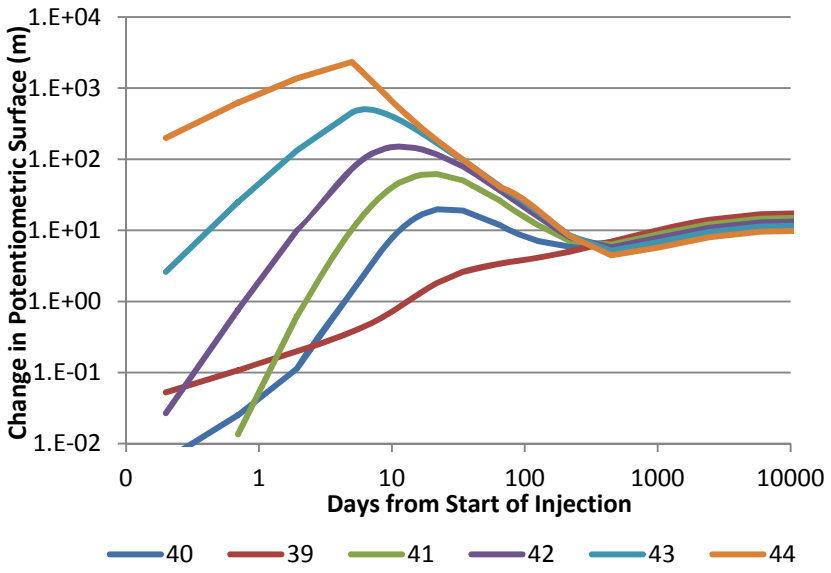


Figure 9: Simulated potentiometric surface changes by layer for specified injection and media properties; Kss=0.01 m/d, Ksh = 0.001 m/d, Kfault = 1 m/d. S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

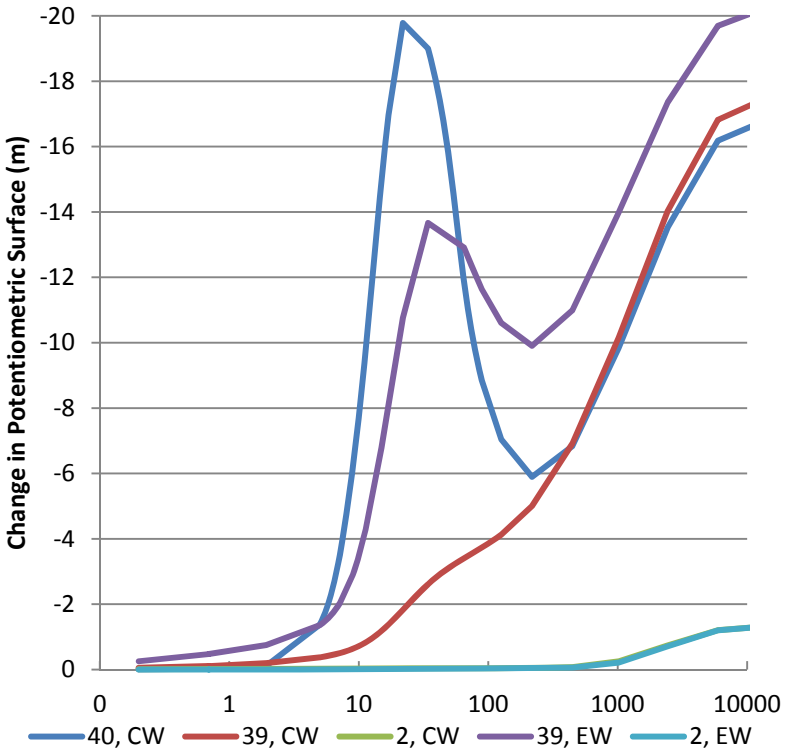


Figure 10: Simulated potentiometric surface changes for layers within the shale and sandstone. CW is center monitoring well and EW is east monitoring well, about 120 m from the centerline. Fault is included. The line for Layer 2, CW plots beneath the line for Layer 2, EW. Kss = 0.01 m/d, Kshale = 0.001 m/d, Kfault=1m/d, S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

Prior to injection, the steady flow for in-situ shale ($K=10^{-5}$ m/d) was generally less than 2 m^3/d and varied little with sandstone K (Figure 5). Once the shale was fractured, the sandstone controlled the flux which ranges from 38 to 135 m^3/d as sandstone K ranges from 0.01 to 0.1 m/d (Figure 10), resulting in particle travel times of 2390 and 616 years, respectively. More conductive shale would allow faster transport (Figure 8). Adding a fault to the scenario with sandstone K equal to 0.01 m/d increased the flux to about 63 m^3/d with 36 m^3/d through the fault (Figure 10) and decreased the particle travel time to 31 from 2390 years. The fault properties control the particle travel time, especially if the fault K is two or more orders of magnitude higher than the sandstone.

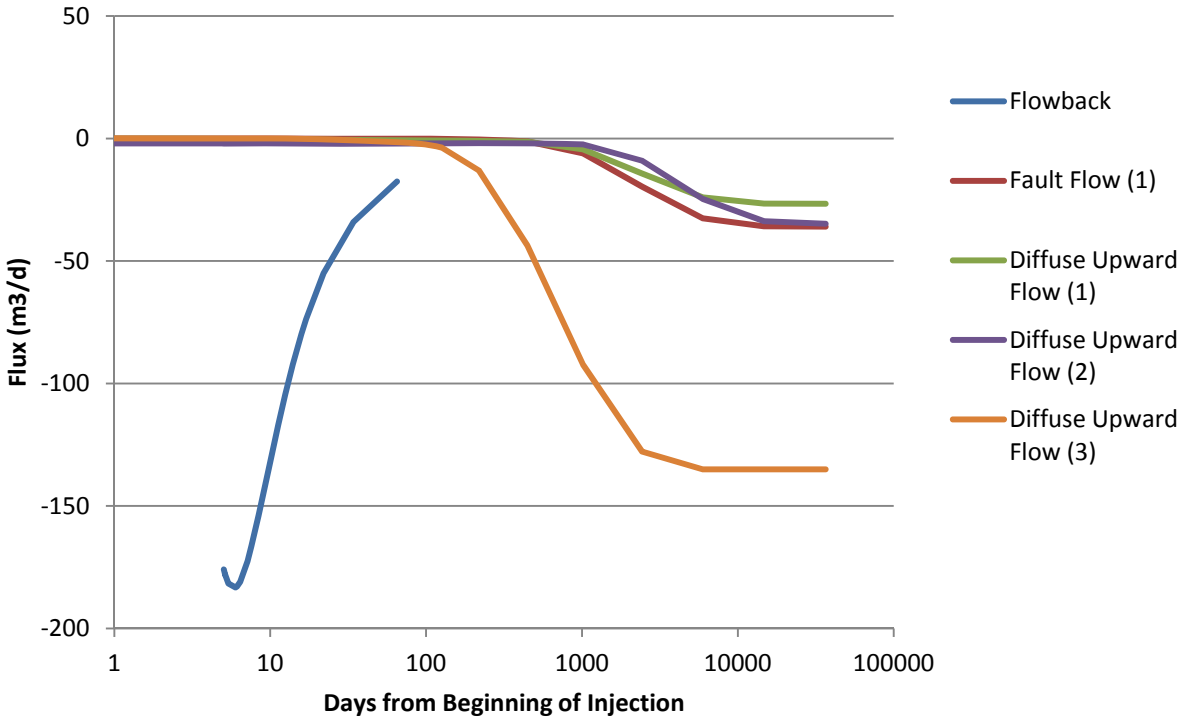


Figure 11: Various fluxes for three separate scenarios. Flowback is the same for all scenarios. (1): Kss=0.01 m/d, Kshale = 0.001 m/d, Fault K = 1 m/d; (2): Kss = 0.01 m/d, Kshale = 0.001 m/d, no fault; (3) Kss= 0.1 m/d, Kshale = 0.001 m/d, no fault.

Simulated flowback varied little with shale K because it had been calibrated to be 20 percent of the injection volume. A lower storage coefficient or higher K would allow the injected fluid to move further from the well, which would lead to less flowback. Lower K would also lead to higher injection pressure which in turn would fracture the shale more.

Vertical flux through the overall section with a fault varies significantly with time, due to the adjustments in potentiometric surface. One day after injection, vertical flux exceeds significantly the pre-injection flux about 200 m above the shale (Figure 11). After 600 days, the vertical flux near the shale is about 68 m^3/d and in layer 2 about 58 m^3/d; it approaches steady state through all sections after 100 years with flux equaling about 62.6 m^3/d. The 100-year steady flux is about 61.5 m^3/d higher than the pre-injection flux because of the changed shale properties.

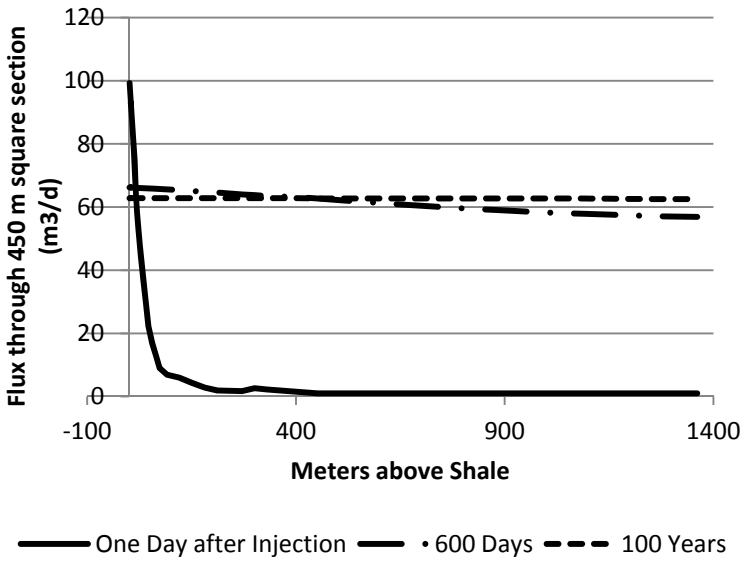


Figure 12: Upward flux across the domain section as a function of distance above the top of the shale layer. Cross section is 202,500 m^2.

Discussion

The interpretative modeling completed herein has revealed several facts about fracking. First, MODFLOW can be coded to adequately simulate fracking. Simulated pressures are high, but velocities even near the well do not violate the assumptions for Darcian flow. Second, injection for five days causes extremely high pressure within the shale that decreases with distance from the well. The time to maximum pressure away from the well lags the time of maximum pressure at the well. The pressure drops back to close to its pre-injection level at the well within 90 days, indicating the injection affects the flow for significantly longer periods than just during the fracking operation. Although the times may vary based on media properties, the difference would be at most a month or so, based on the various combinations of properties simulated. The system transitions within six years due to changes in the shale properties. The same order of magnitude would apply to changes in shale properties from less to more conductive. The equilibrium transport rate would transition from a system requiring thousands of years to one requiring hundreds of years or less within less than ten years.

Third, most of the injected water in the simulation flows vertically rather than horizontally through the shale. This reflects the higher sandstone K 20 m above the well and the no flow boundary within 225 m laterally from the well, which emulates in-situ shale properties that would manifest at some distance in the shale.

Fourth, the interpretative model accurately and realistically simulates long-term steady state flow conditions, with an upward flow that would advect whatever conservative constituents exist at depth. Using low, unfractured K values, the transport simulation may correspond with advective transport over geologic time although there are conditions for which it would occur much more quickly (Figure 5). If the shale K is 0.01 m/d, transport could occur on the order of a few hundreds of years. Faults through the overburden could speed the transport time considerably. Reasonable scenarios presented herein suggest the travel time could be decreased further by an order of magnitude.

Fifth, fracking increases the shale K by several orders of magnitude. The regional hydrogeology changes due to the increased K. Vertical flow could change over broad areas if the expected density of wells in the Marcellus shale region (NYSDEC 2011) actually occurs.

Sixth, fault fracture zones coming close to contacting the newly-fractured shale could allow contaminants to reach surface areas in tens of years. Faults can decrease the simulated particle travel time several orders of magnitude.

Conclusion

Fracking can release fluids and contaminants from the shale either by changing the shale hydrogeology or simply by the injected fluid forcing other fluids out of the shale. The complexities of contaminant transport from hydraulically fractured shale to near-surface aquifers render estimates uncertain, but a range of interpretative simulations suggest that transport times could be decreased from geologic time

scales to as few as tens of years. Preferential flow through fractures could further decrease the travel times to as little as just a few years.

There is no data to verify either the pre- or post-fracking properties of the shale. The evidence for potential vertical contaminant flow is strong, but there are also almost no monitoring systems that would detect contaminant transport as considered herein. Several improvements could be made.

- Prior to hydraulic fracturing operations, the subsurface should be mapped for the presence of faults and measurement of their properties
- A reasonable setback distance from the fracking to the faults should be established. The setback distance should be based on a reasonable risk analysis of fracking increasing the pressures within the fault.
- The properties of the shale should be verified, post-fracking, to assess how the hydrogeology will change.
- A system of deep and shallow monitoring wells and piezometers should be established in areas expecting significant development, before that development begins (Williams 2010).

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Current and Projected Water Use in the Texas Mining and Oil and Gas Industry



Prepared for
Texas Water Development Board

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Cover photo: Aggregate facility in Bexar County (courtesy of Google Earth)

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Glossary and Abbreviations

AAPG	American Association of Petroleum Geologists
AF	Acre-foot (1 AF = 325,851 gallons)
Bbbl	Billion barrels
Bcf	Billion cubic feet (1 Bcf = 10^3 MMcf = 10^6 Mcf)
bgs	below ground surface
BTU	British Thermal Unit
CBM	Coal-bed methane
CCS	Carbon capture and storage
EIA	Energy Information Agency
EOR	Enhanced oil recovery
EUR	Estimated ultimate recovery
GAM	Groundwater availability model
GC	Gulf Coast
GCD	Groundwater conservation district
GIP	Gas-in-place
GSA	Geological Society of America
IP	Initial production
ISL	In situ leaching
ISR	In situ recovery
LCRA	Lower Colorado River Authority
LPG	Liquefied petroleum gas
MAF	Thousand acre-feet
MGD	Million gallons per day
Mcf	Thousand cubic feet
MMbbl	Millions of barrels
MMBTU	Million BTU
MMcf	Million cubic feet (1 MMcf = 10^3 Mcf)
NGL	Natural gas liquid
NGW	Natural Gas Week Journal
NOGA	National oil and gas assessments (by USGS)
NORM	Naturally occurring radioactive materials
O&GJ	Oil and Gas Journal
OOGP	Original gas in place
OOIP	Original oil in place
OSHA	Occupational Safety and Health Administration

PBSN	Powell Barnett Shale Newsletter
PGC	Potential Gas Committee
PPA	Pounds of proppant added per gallon of fluid
RRC	Railroad Commission of Texas
RWPG	Regional water planning group
SIC	Standard industrial classification
st	Short ton
TACA	Texas Aggregate and Concrete Association
TCEQ	Texas Commission on Environmental Quality
Tcf	One trillion cubic feet (1 Tcf = 10^3 Bcf = 10^6 MMcf = 10^9 Mcf)
TDS	Total dissolved solids
Th. AF	Thousand acre-feet
TMPA	Texas Municipal Power Agency
TMRA	Texas Mining and Reclamation Association
TOC	Total organic content
TWBD	Texas Water Development Board
TXOGA	Texas Oil and Gas Association
UIC	Underground injection control
USGS	U.S. Geological Survey
VR	Vitrinite reflectance
WAG	Water alternating gas
WCAC	Water Conservation Advisory Council
WUG	Water user group (TCEQ jargon)
WUS	Water use survey (TWDB jargon)

Note to the reader:

In the oil industry m or M stands for 1,000 (one thousand, as in Mcf, one thousand cubic feet) but it means million in the water industry (as in MGD, million gallons per day). We try to spell out numbers or use plain units to limit the confusion.

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1 Executive Summary

In the middle of 2009, we undertook a study of water use in the so-called mining industry in Texas, both current and projected for the next 50 years. The study concerned the upstream segment of the oil and gas industry (that is, water used to extract the commodity until it leaves the wellhead), the aggregate industry (sand and gravel and crushed rock operations, washing included but no further processing), the coal industry (mostly pit dewatering and aquifer depressurizing), and other substances mined in a fashion very similar to that of aggregates (industrial sand, lime, etc.), as well as through solution mining. In general we followed the definition of mining according to SIC/NAICS codes. It follows that cement facilities, despite their large quarries, are considered to belong to the manufacturing, not mining, category. The objective of the study, that was essentially prompted by the sudden increase in shale-gas production, was to help in the next cycle of water planning by the state agency in charge of such planning, the Texas Water Development Board (TWDB).

The approach to the study is twofold: (1) to collect water-use data and auxiliary information by contacting actual mining facilities and (2) to interview experts and other knowledgeable individuals in their respective fields to fill in the gaps in water-use data and to understand future development/contraction of water use in the different segments of the mining industry. We surveyed the industry either through formal questionnaires sent to the membership of trade associations (TACA for aggregates; TMRA for aggregate, coal, and uranium; TXOGA and others for oil and gas), through surveys sent to water providers/observers such as GCDs, or through survey results from other organizations (MSHA, RRC, TCEQ, TWDB, USGS), and especially private vendors of the oil and gas industry. We contacted and had in-depth interviews with multiple representatives of every major segment of the mining industry to help us understand how the water is used, how much is recycled, what its source is (groundwater, surface water or something else), whether it is fresh or brackish (saline water use is not tallied in this study), how much is rejected outside of the mining facility, etc.

Results from the surveys were useful but not as extensive as hoped for us to assemble a representative sample of the hundreds of mining facilities in the state, with the exception of the coal industry (a significant water user) and the uranium industry (a minor water user). We were also able to gather relatively accurate data from the stimulation stage when a well is being readied for production (the so-called fracing process), but we are more uncertain about water use for drilling wells and waterfloods. Results of current water use for the aggregate industry relied on previous information somewhat calibrated and updated by survey results. Overall, in 2008 (latest year with complete information), we estimate that the state used ~139 thousand acre-feet (AF) in the mining industry (Figure ES1), including 35.8 thousand AF for fracing wells (mostly in the Barnett Shale/Fort Worth area) and ~21.0 thousand AF for other purposes in the oil and gas industry, although more spread out across the state, with a higher demand in the Permian Basin area in West Texas. The coal industry used 26.7 thousand AF along the lignite belt from Central to East Texas. The 43.0 thousand AF used by the aggregate industry is distributed over most of the state, but with a clear concentration around major metropolitan areas. The remainder amounts to 12.2 thousand AF and is dominated by industrial sand production (~80% of total).

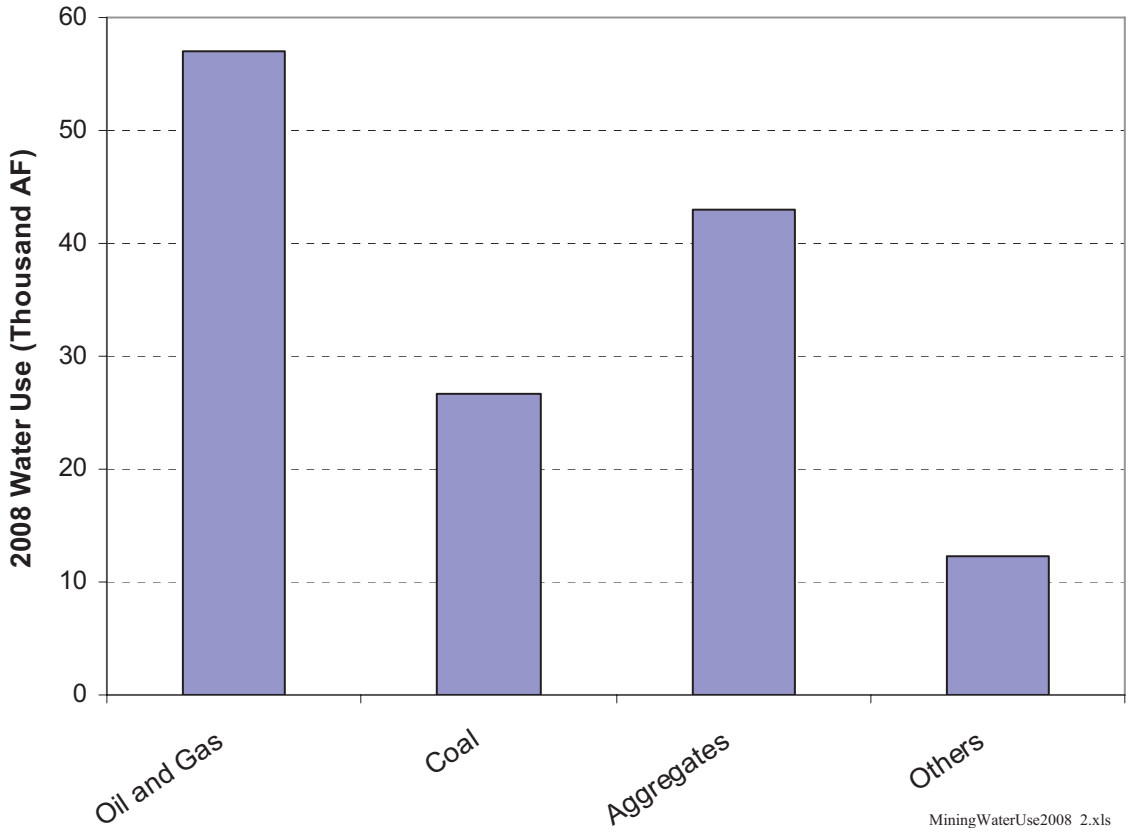


Figure ES1. Summary of estimated water use by mining industry segment (year 2008)

Water is used mostly for drilling wells, stimulating/fracing wells, and secondary and tertiary recovery processes (oil and gas industry); for dewatering and depressurizing pits, with a small amount used for dust control (coal industry); and for dust control and washing (aggregate industry and industrial sand). Reuse/recycling has been accounted for in water-use figures, as well as opportunity usages, such as stormwater collection (aggregates). As such, the numbers represent mostly consumption. Only some of the coal-water use could be construed as nonconsumed withdrawal when groundwater extracted for depressurization purposes is discharged into streams (40–50% of total). The split between surface water and groundwater is difficult to assess, short of having information directly from facilities (such as for coal and some aggregate facilities), especially for exempt use in the oil and gas industry.

Projections for future use were done by extrapolating current trends, mainly for coal (more or less stable) and aggregates (following population growth). Projections for the oil and gas industry were made with the help of various sources by estimating the amount of oil and gas to be produced in the state in the next decades and by distributing it through time. Given the volatility of the price of oil and gas, it is easy to see that the figures provided are only indicative of a possible future. We projected that the state overall water use will peak in the 2020–2030 decade at ~250 thousand AF (Figure ES2), thanks to the oil and gas unconventional resources that will start to decrease in terms of water use around that time. Both coal and aggregates are slated to keep increasing, more strongly for aggregates.

Note (1) that we endeavored to generate results at the county level but, given the uncertainty inherent to future production and to the approach, we estimate that individual counties may be

off by a factor of 2 or 3, although a group of counties will have a much lower range of uncertainty; (2) that projections presented in this report are not binding to the facilities cited in the report and are made through integration of many other external factors; and (3) that these figures do not represent official TWDB projections but that they will be used as a tool by TWDB to make official projections for use in the next water-planning cycle.

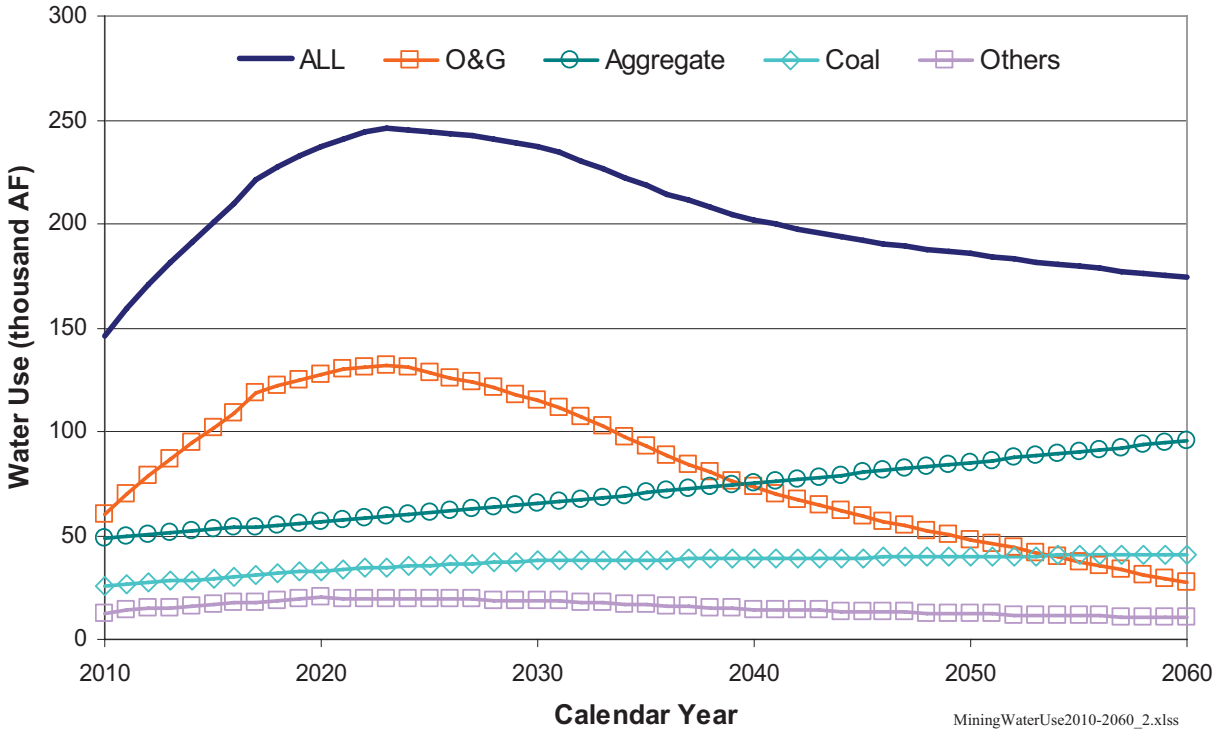


Figure ES2. Summary of projected water use by mining industry segment (2010–2060)

.

2 Introduction

The Texas Water Development Board (TWDB) has contracted the Bureau of Economic Geology (BEG) at The University of Texas at Austin to compile information about current water use in the mining industry (to be more thoroughly defined later) and to make water-use projections for the next 50 years to 2060. The project was launched as a response to a Request for Statements of Qualifications on Topic 3 of the 2009 Water Research Study Priority Topics by TWDB Water Resources Planning Division, headed by Dr. Dan Hardin. The present report documents results for the four tasks described in the scope of work of Contract #0904830939: (1) identify major mining operations and analyze water-use patterns, (2) estimate current water use withdrawal and consumption (3) develop long-term water-demand projections at the county level, and (4) report the findings of the study and prepare an electronic database. The project is the result of the collaboration between the Bureau of Economic Geology at The University of Texas at Austin; Steven Walden Consulting, Austin, TX; Texerra, Midland, TX; and LBG-Guyton, Austin, TX. The project also benefited from strong cooperation from major players in the Texas mining industry, particularly the following trade associations: Texas Mining and Reclamation Association (TMRA), Texas Aggregate and Concrete Association (TACA), and Texas Oil and Gas Association (TXOGA).

The report is divided into several sections. In each of them, we successively address oil and gas, coal, aggregates, and other mineral substances. Oil and gas activities are not always necessarily compiled with other mining activities, but they are for the purpose of this report. It is also consistent with the way the federal government catalogs all economic activities (SIC and NAICS codes; more on this later). In the next few paragraphs, we present an overview of the mining industry in Texas and a high-level discussion of its water use. In Section 3, we describe the methodology used to generate figures for current and projected water use. Section 1 describes current water use, whereas Section 5 addresses projected water use. The general approach in the latter section consists of extrapolating historical and current water-use trends and applying some corrections. We think that quantitatively attempting to include new processes or events that might emerge or occur in 50 years is a worthless exercise. The current shale-gas boom, largely unforeseen by industry watchers, is a case in point. It follows that projections are mostly valid in the 5- to 10-year term. We did add a subsection on speculative resources, whose water-use figures were not included in final totals.

2.1 Overview of Mining Activities in Texas and a High-Level Perspective on Water Use in the Industry

2.1.1 Mined Substances

Before water use is discussed in detail, an understanding of the big picture, as well as the mining landscape in terms of operations, might be useful. USGS publishes regular updates to national nonfuel mining activities (http://minerals.usgs.gov/minerals/). The latest USGS (2009) compilation uses data from 2006 (Table 1). Estimated value of nonfuel minerals is $3.0 billion, 62% of which is related to cement activities. Note that cement is included in the USGS compilation, although neither cement plants nor allied quarrying operations are included in this report. This definition of mining is consistent with previous approaches by TWDB. Oil and gas

importance dwarfs that of other minerals in terms of value (>$50 billion) but, as documented in this report, not in terms of water use (Table 1).

Recently BEG (Kyle, 2008) released a factsheet presenting the industrial minerals in Texas consistent with information provided by the USGS. Kyle and Clift (2008) also provided geologic background, explaining in general regional terms why the diverse facilities are located where they are and the uses of these mined substances. In addition to the oil and gas produced over most of the state and to the coal produced within a narrow inland section parallel to the coast, the mining industry, in terms of volume, generates value through sand and gravel, mostly exploited along rivers, and crushed stone, mostly present in the footprint of the Edwards Limestone.

Oil and gas resources are generally sorted into conventional and unconventional categories (Figure 1 and Figure 2). The former represents the archetypal reservoir traps in either sandstones or carbonates and is made up of interconnected pores that allow "easy" communication with the well bore. The latter is generally characterized by the use of advanced technologies and consists of different types of formation and/or extreme environmental conditions (pressure and temperature). In terms of amount produced, unconventional resources have already passed the "conventional" reservoirs (Stevens and Kuuskraa, 2009). Relevant characteristics include low permeability and a need to stimulate the reservoir through hydraulic fracturing. In this study, the unconventional category consists of tight formations, usually "tight gas," and resource plays such as gas shales and liquid-rich shales. We do not describe the technology in this document; see, for example, King (2010) for a summary. Coalbed methane (CBM), producing mostly gas, could also be added to the list of unconventional reservoirs. Resource plays are generally defined as those plays with relatively predictable production rates and costs and with a lower commercial risk, as compared with conventional plays. Gas-shale plays with their extensive, continuous resources and "no dry well" are examples of resource plays. The challenge for operators is to find those sweet spots that will produce gas at a profit.

Note that the exact terminology to describe hydraulic fracturing as practiced by the oil and gas industry has not been settled yet. We opted for "*frac*", "*fracing*" and "*fraced*" although "*frack*", "*fracking*" and "*fracked*" would have been acceptable too. We also refer to "*gas shales*" when the focus is on the formations as a generic term including Barnett, Eagle Ford, etc shales. In contrast, the terms "*shale gas*" or "*shale oil*" suggest that the focus is on the commodity itself not the formation. The term "*oil shale*" is sometimes understood as mostly applicable to those formations in Utah and Colorado which require more efforts and energy to recover the oil. To avoid confusion with common usage, we settled on the term "*liquid-rich shale*".

Coal is generally ranked as anthracite, bituminous, subbituminous, or lignite, listed in decreasing order of energy content. Low-rank, low-energy coals include lignite and subbituminous coals, and they are the only coals present in Texas in significant amounts (Figure 3). High-rank coals, including bituminous and anthracite coals, contain more carbon and lower moisture than lower-rank coals, and thus have higher energy content. Coal has been produced in Texas since the late 1880's. At that time the most common mining method was underground mining, but currently only surface mining is utilized. Lignite makes up most of the current coal production and will do so in the near future as well. Whereas bituminous resources are still available, the economically recoverable resources have already been mined. The lignite belt stretches diagonally across Texas from Louisiana to Mexico. It is represented by the Wilcox, Jackson, and Claiborne Formations of the upper Gulf Coast, whereas, farther west, Pennsylvanian and Permian pockets

represent bituminous resources. BEG has published many reports on Texas coal (for example, Fisher, 1963; Henry and Basciano, 1979; Kaiser et al., 1980).

Aggregates (Figure 4), as sand and gravel and crushed stone are collectively known, are the most important category in terms of volume and dollar amount, after the oil and gas industry. Crushed stone consists mostly of limestone and dolomite, with many facilities located along the IH35 corridor (San Antonio to the Dallas-Fort Worth metroplex) (Figure 5). Because of important capital costs, those operations tend to be larger than the sand and gravel facilities. The latter are concentrated along streams and on the coast (Figure 6). Allied mined substances include industrial sand and dimension stone. There are other substances but they tend to be mined at only a few locations (Table 2 and Table 3). Note that several mining activities do not require fresh water or even water. Brine production may require fresh water for drilling wells, but its use is nominal, which is equally true for gas wells producing from conventional reservoirs. Another less systemic example is crushed stone operations, which uses water only for occasional dust suppression.

2.1.2 Mining Facilities

The first step of the study, before estimating water use, consisted of determining the actual number of mining facilities. Their spatial distribution and count at the county level represent the next level of complexity as they guide the final mining water use at the county level. Oil and gas operations are present in most Texas counties. Number of traditional mining facilities is given by several sources, the most complete being from the U.S. Census Bureau (USCB). USCB reports survey data every 5 years. The 2002 survey was released in 2005, and the 2007 had not been released at the time this report was written. Disregarding oil and gas wells and other oil- and gas-related facilities, the USCB listed a total of 11 lignite mines, 100+ crushed stone and ~200 sand and gravel operations, many of them small, and ~70 facilities of a different type, neither lignite nor aggregate. Not counting wells tapping the subsurface (solution mining), the vast majority of operations are open-pit operations. USCB (2005) reported six underground mining operations in 2002, all but one (rock-salt operation) being very small.

MSHA (Mining Safety and Health Administration) also manages a database of abandoned and active mines across the country because mines must submit health and safety applications and obtain permits. As of July 2010, 1,869 abandoned and 692 active mines (including cement plants and coal mines) were officially registered in the state of Texas (Table 3). However, the overlap with USCB data is not perfect because the MSHA database includes (1) facilities treating the raw material but not necessarily extracting it locally and (2) nonactive facilities that have not been officially abandoned.

The database for the Source Water Assessment and Protection (SWAP) program, a federally mandated program managed by the Texas Commission of Environmental Quality (TCEQ), contains an inventory of potential sources of contamination (POSC) susceptible to contaminating sources in potable water (both groundwater wells and surface-water intakes). Those sources include a whole range of human activities from cemeteries to gun ranges to dry cleaners, including mining facilities (“Natural Resource Production”). TCEQ cites the Railroad Commission of Texas (RRC), the U.S. Geological Survey (USGS), and BEG as sources for the mining subset of the database. Information that can be depicted on an aquifer map is a more detailed and useful inventory than a listing of facilities (Figure 7, Bastrop and Lee Counties).

2.1.3 Water-Use Overview

Overall, mining water use in Texas represents only a small fraction of total water use in the state, and estimates have varied, given the relatively low priority of this category of water use. Previous water-demand surveys and projections estimated ~280 thousand AF as the demand for water use in mining compared with 17 million AF (1.6%) for total water use in 2000 (TWDB, 2007, Table 4.2), ~250 thousand AF and ~17 million AF (TWDB, 2002, Table 5.2), and ~200 thousand AF and ~16.5 million AF (TWDB, 1997, Table 3.2), both also for year 2000 (Table 4). Those figures represent only fresh water, the generally accepted definition of which is any water with a total dissolved solid content (TDS) <1,000 mg/L. Livestock as well as crops tolerate higher TDS, perhaps as high as 6,000 and 10,000 mg/L, respectively. Some sources define fresh water as water <3,000 mg/L. Inability to reconcile the different definitions adds uncertainty to the final figures provided in this report. Under the Safe Drinking Water Act, any <10,000 mg/L non-exempt aquifer is considered a potential underground source of drinking water. Note that there is no consistency (including in the documents cited in this work) in the definitions of fresh, brackish, and saline water which depend mostly of the context.

The overarching goal of this report is to confirm these figures. We provide some explanation on why results presented in this report differ from previous projections by TWDB, but they are due mostly to a change in accounting and to the impact of shale-gas production. The work presented in this report will not formally be included in the 2012 water plan, but will inform it. An issue of great impact to this work is the split between groundwater and surface water. This information is not always easy to identify, but in the course of this project, we tried to collect as much as possible. Approximately 59% of the water used in the state is groundwater (TWDB, 2007, p. 176), although this statistic is biased because a sizable fraction comes from the Ogallala aquifer in the Texas Panhandle and is used for irrigation. In this area of Texas the groundwater-use fraction is somewhat higher, whereas elsewhere it tends to be smaller. Irrigation is an important category used by TWDB to detail water use in the state and is the largest in terms of volume. Other categories in approximately decreasing volumes are municipal, manufacturing, steam-electric, livestock, mining, and domestic/other.

In addition to efforts at the state level, several federal organizations interpret information flowing from the states. USGS publishes every 5 years (with a lag of a few years relative to data collection) information about all types of water use across the nation. The most recent versions are authored by Kenny et al. (2009) for year 2005 and by Hutson et al. (2005) for year 2000 (Table 5). Sources of data feeding the reports are left to the judgment of local state offices and vary with water-use type and state (Kenny, 2004). For the State of Texas, BEG, RRC, TCEQ, and TWDB are typically contacted. USGS also performs its own survey, although it is not always successful in obtaining comprehensive information from all facilities. USGS typically extrapolates from the information obtained and publishes only aggregated data. For the State of Texas, Kenny et al. (2009, Table 2B) reported a mining-water withdrawal of 102 and 614 thousand AF/yr, respectively, for water of fresh (defined in the USGS report as <1,000 mg/L) and saline (>1,000 mg/L) quality. All saline water was reported as groundwater, whereas only 30 thousand AF of the fresh-water category was reported as groundwater (Kenny et al., 2009, Table 3B and Table 4B). Most of the saline water is counted toward secondary recovery of hydrocarbons (disposal not included). Kenny et al. (2009, p. 35) stated that dewatering operations are included in the water withdrawal total only if the water is put to beneficial use (for example, dust control). The work presented in this report follows a different approach (see

section on Methodology). USGS figures for the year 2000 (Hutson et al., 2005, Table 4) are somewhat different and more closely align with those of the TWDB, with a total fresh-water use of 246 thousand AF (144 groundwater and 102 surface water). The total amount of saline water (produced water) at 565 thousand AF is not sizably different. Whereas 1995 (Solley et al., 1998) figures are consistent with those of 2000, the difference between 2000 and 2005 figures corresponds to a change in accounting.

2.2 Overview of Recent Projections

The TWDB Office of Planning provides projection figures to the State Water Plan (e.g., TWDB, 2007). Norvell (2009) represents the latest effort before the work presented in this report. An earlier effort by a consultant on behalf of TWDB (2003) includes manufacturing in addition to mining. Both Norvell (2009) and TWDB (2003) attempted to link economic activity at the county level to water use. In essence, the approach consisted of developing a correlation between historical water use and economic output at the county level and extrapolating future water use from a forecast of economic activity. The correlation was made through so-called water-use coefficients (ratio of water use and gross economic output) determined at the county level. Mining-specific constraints were dismissed and hidden as being part of the overall economic activity (TWDB, 2003, p. 2–3). Overall, results of this approach were not very satisfying for the mining category.

Table 1. Fuel and nonfuel raw mineral production in Texas

Mined Substance	Quantity	Approx. Value (1,000s of $)
	MMbbl	**~$57/bbl[f]**
Oil[a]	344.5	~19,000,000
	Tcf	**$5/Mcf[g]**
Gas[b]	7.53	~37,650,000
	1000s short tons	**~$18/Short ton[h]**
Coal/lignite[c]	37,099	~668,000
Uranium[d]	Withheld	Withheld
Nonfuel Minerals[e]	**1000s metric tons**	
Cement (overwhelmingly portland)	11,682	1,120,700
Clays (common clay, bentonite)	2,289	14,900
Gypsum	1,430	11,800
Lime	1,650	130,000
Salt	9,570	132,000
Sand and gravel:	99,500	603,000
Industrial sand	1,530	65,600
Crushed stone:	136,000	824,000
Dimension stone	31[i]	12,600
Subtotal		2,902,000
Other: talc, brucite, clays (Fuller's earth, kaolin), helium, zeolites, sulfur		78,000
Total		2,980,000

Source: [a]: http://www.rrc.state.tx.us/data/production/oilwellcounts.php —2009 data;
[b]: http://www.rrc.state.tx.us/data/production/gaswellcounts.php —2009 data;
[c]: http://www.rrc.state.tx.us/industry/_COALPRODthru2009.XLS —2009 data;
[d]: Information withheld for confidentiality (small number of producers)
[e]: USGS (2009) —2006 data;
[f]: 2009 annual average for Texas; http://www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm
[g]: 2009 annual average for Texas; http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_STX_a.htm
[h]: 2008 annual average for Texas; http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html
[i]: Seems to be a slow year or underreporting

Table 2. Estimate of the number of mining facilities in the State of Texas in 2002 (USCB)

Industry Type	Total Number of Establishments	>20 Employees
Crude petroleum and natural gas extraction	2803	286
Natural gas liquid extraction (includes sulfur extraction)	180	57
Total Oil and Gas Extraction	**2983**	**343**
Bituminous coal and lignite surface mining	11	9
Total Coal Mining	**11**	**9**
Fe ore mining	3	0
Au ore and Ag ore	4	0
Cu, Ni, Pb, and Zn ore mining	1	0
U, Ra, V ore mining	5	1
Other metal ore mining	2	0
Total Metal Ore Mining	**15**	**1**
Dimension stone mining and quarrying	18	5
Crushed and broken limestone mining and quarrying	71	23
Granite mining and quarrying	3	0
Other crushed and broken stone mining and quarrying	15	5
Total Stone Mining and Quarrying	**107**	**33**
Construction sand and gravel mining	198	51
Industrial sand mining	19	5
Kaolin and ball clay mining	1	1
Clay and ceramic and refractory minerals mining	11	4
Total Sand, Gravel, Clay, and Ceramic, and Refractory Minerals Mining and Quarrying	**229**	**61**
Potash, soda, and borate mineral mining	1	1
Other chemical and fertilizer mineral mining	6	1
All other nonmetallic mineral mining	19	2
Total Other Nonmetallic Mineral Mining and Quarrying	**26**	**4**
Total Nonmetallic Mineral Mining and Quarrying	**362**	**98**

Source: USCB (2005)

Table 3. Number and diversity of minerals mining operations in Texas (MSHA)

Primary Commodity	# of Fac.	Primary Commodity	# of Fac.
Alumina	2	Dimension sandstone	11
Barite barium ore	7	Dimension stone NEC	47
Bentonite	3	Dimension traprock	1
Cement	12	Fire Clay	7
Clay, ceramic, refractory mnls.	2	Gypsum	8
Common clays NEC	19	Iron ore	6
Common shale	2	Lime	2
Construction sand and gravel	250	Manganese ore	1
Crushed, broken granite	1	Misc. nonmetallic mnls. NEC	1
Crushed, broken limestone NEC	167	Pigment minerals	1
Crushed, broken marble	3	Potassium compounds	1
Crushed, broken sandstone	6	Salt	2
Crushed, broken stone NEC	52	Sand, common	15
Crushed, broken traprock	3	Sand, industrial NEC	10
Dimension limestone	32	Talc	5
Dimension marble	1	Zeolites	1

NEC:
Source: MSHA (http://www.msha.gov/DRS/DRSextendedSearch.asp), data from June 2008

Table 4. Historical projected mining water use (top) and total water use (bottom) for all water uses in Texas by TWDB (MAF)

Water Plan	1990	2000	2010	2020	2030	2040	2050	2060
1997	149 15,729	205 16,586	187 16,867	182 17,135	191 17,489	194 17,900	188 18,354	
2002	149 15,729	253 16,919	246 17,662	245 18,195	252 18,732	252 19,369	244 20,022	
2007		279 16,977	271 18,312	281 19,011	286 19,567	276 20,105	277 20,759	286 21,617

Source: TWDB (1997, 2002, 2007)

Table 5. Historical mining water use in Texas by USGS (thousand AF)

	Fresh	Saline	Total
1995			
Groundwater	143	458	602
Surface water	93	0	93
Total	236	458	694
2000			
Groundwater	144	565	709
Surface water	102	0	102
Total	246	565	811
2005			
Groundwater	30	614	644
Surface water	72	0	72
Total	102	614	716

Source: Kenny et al. (2009), Hutson et al. (2005), Solley et al. (1998)

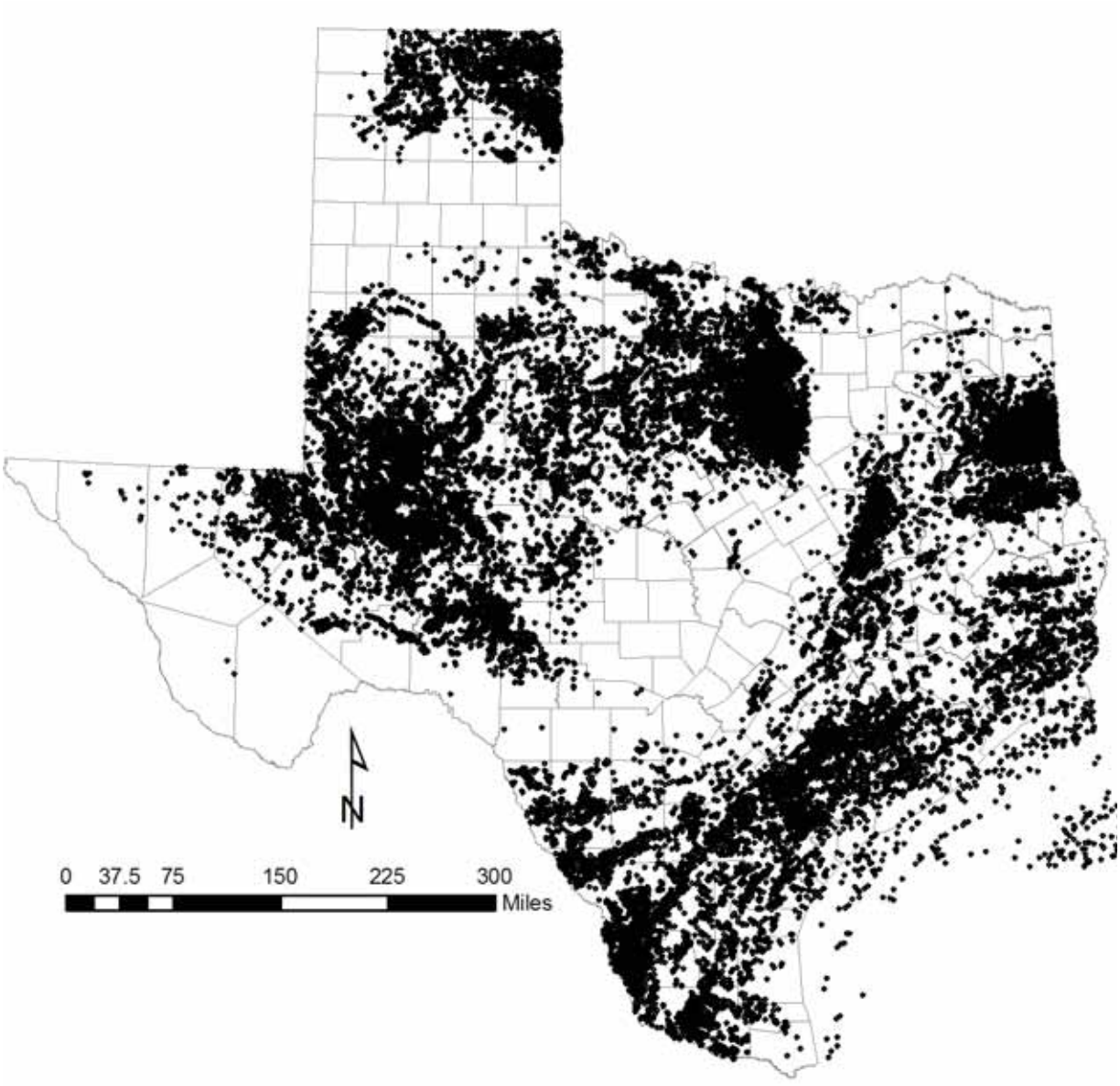
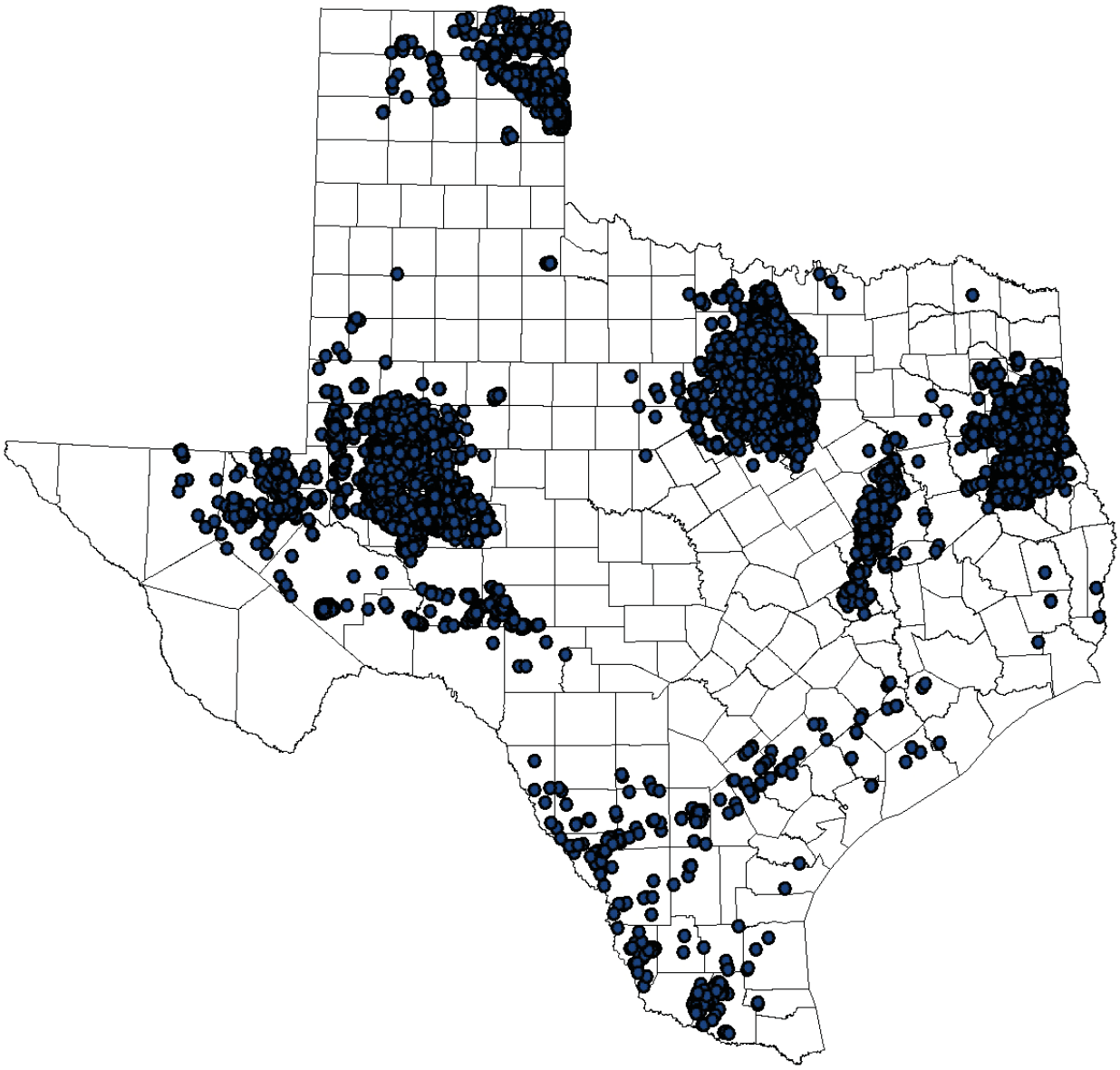


Figure 1. Location map of all wells with a spud date between 2005/01/01 and 2009/31/12 (approximately ~75,000 wells)



Source: IHS database

Figure 2. Map showing locations of all frac jobs in the 2005–2009 time span in the state of Texas. Approximately 23,500 wells are displayed

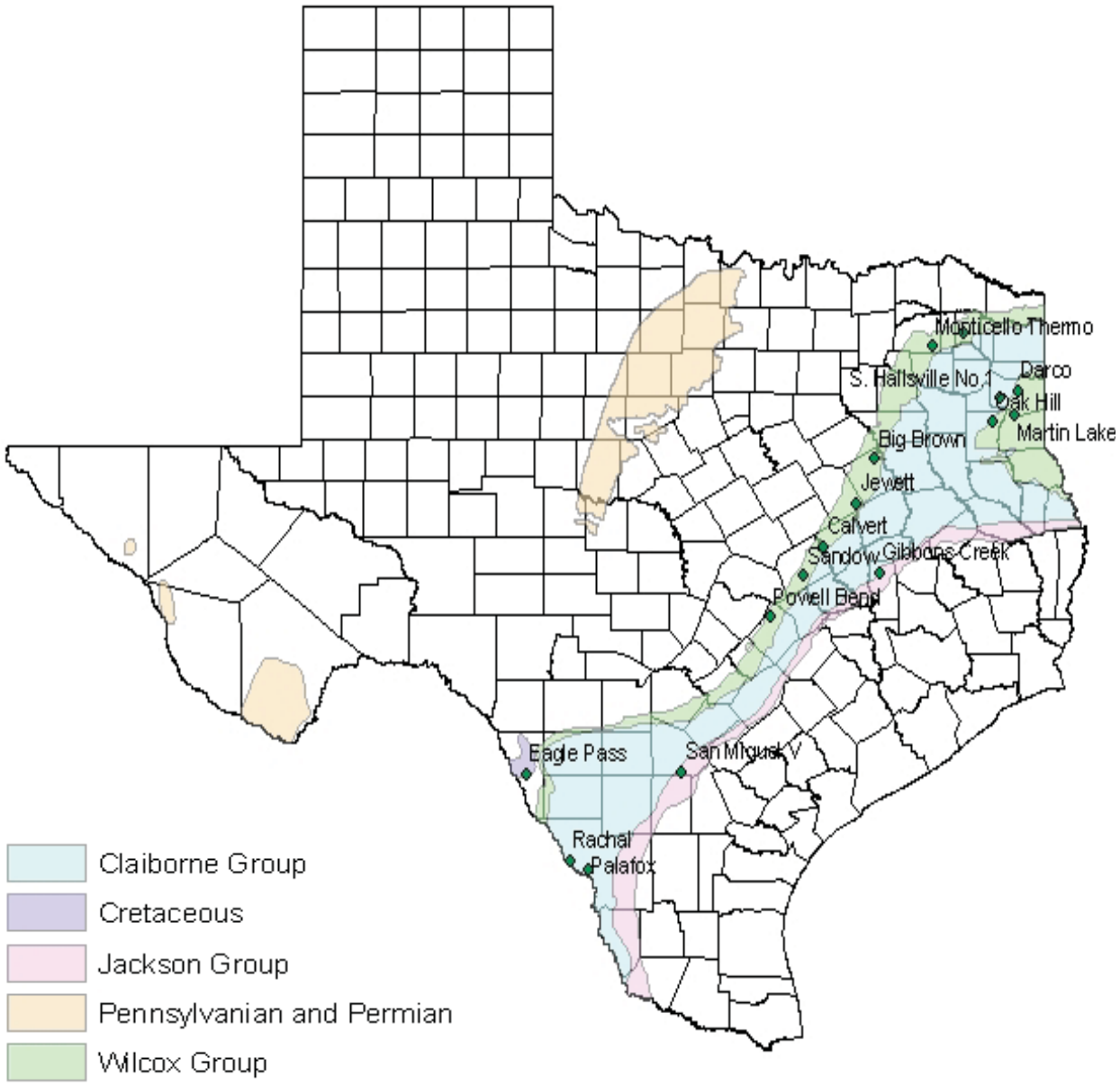
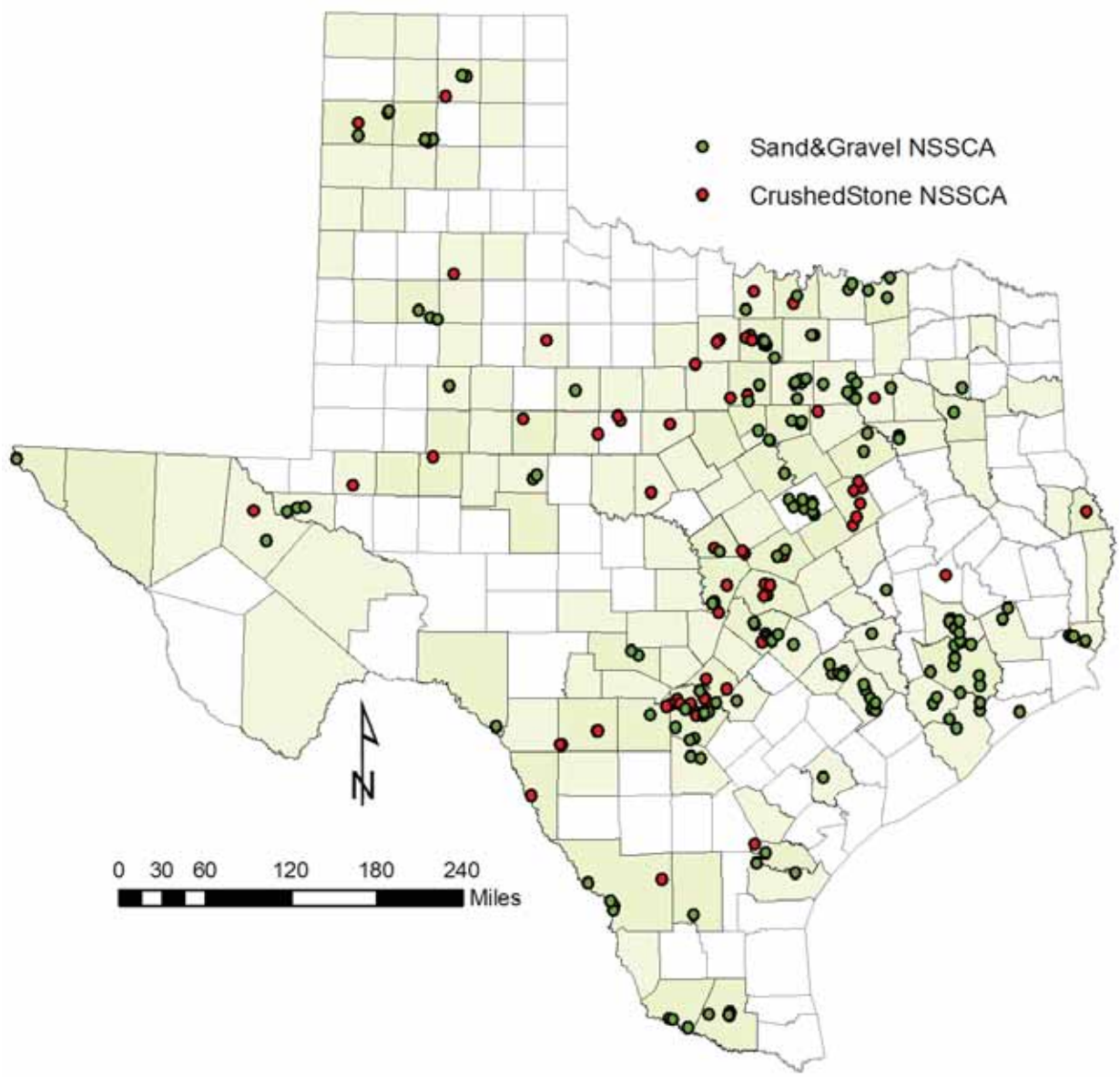
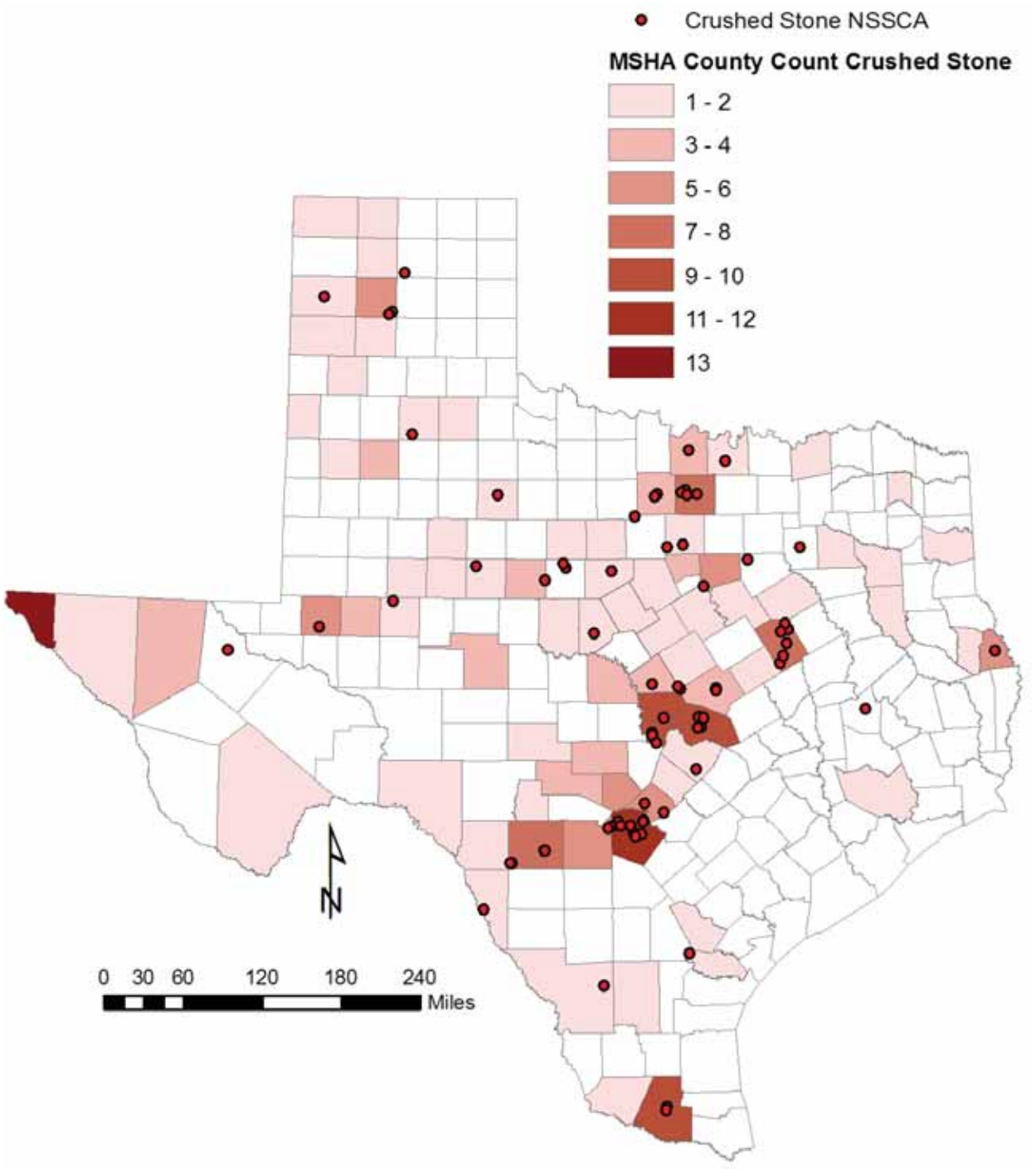


Figure 3. Location map of coal/lignite operations



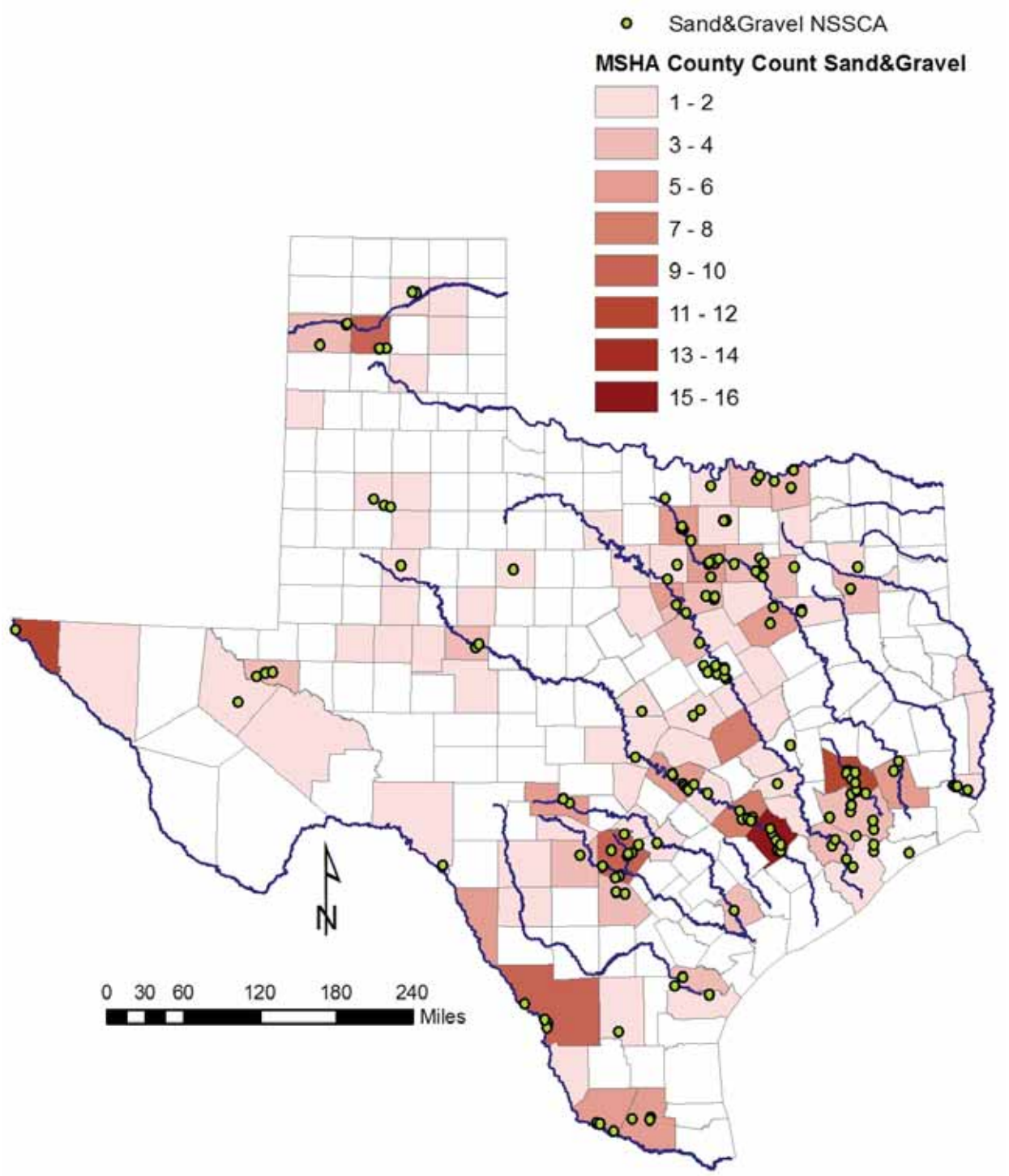
Source: NSSGA/USGS database and MSHA database
Note: deleted from the NSSGA database were all facilities whose names included "yard," "asphalt," "concrete," or "cement," as well as plants of well-known cement producers; facilities with "chemical" are treated in the other nonfuel minerals section (Section 4.5)

Figure 4. Location map of aggregate operations from NSSGA database (data points) and MSHA database (selected counties)



Source: NSSGA/USGS database and MSHA database

Figure 5. Location map of crushed-stone operations from NSSGA database (data points) and MSHA database (selected counties illustrating number of operations)



Source: NSSGA/USGS database and MSHA database

Figure 6. Location map of sand and gravel operations from NSSGA database (data points) and MSHA database (selected counties illustrating number of operations)

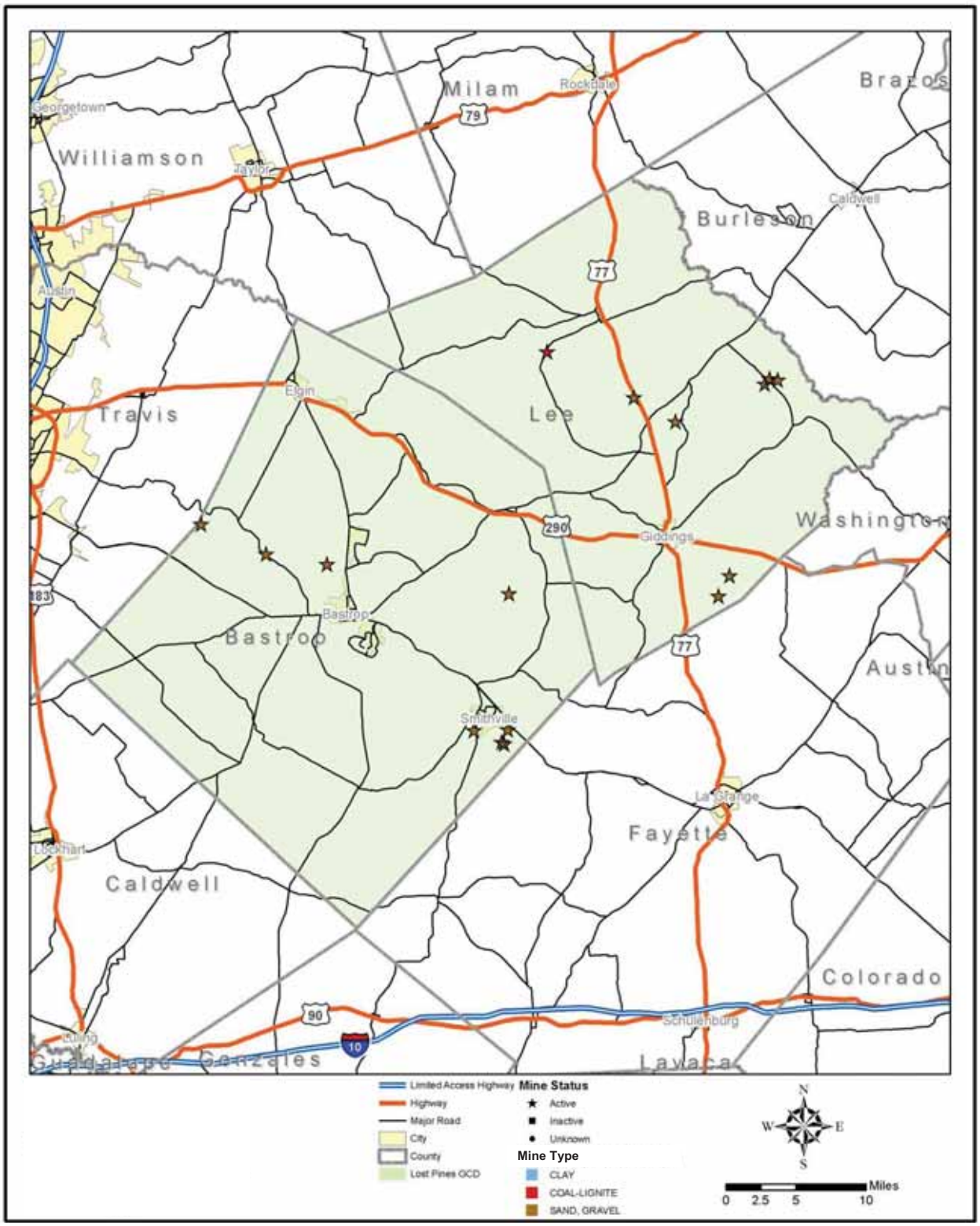


Figure 7. Example or representation provided by the SWAP database

3 Methodology and Sources of Information

With thousands of operations in the state and with no legal requirement to report production and water use (except partly for oil, gas, and coal), some choices had to be made to deliver an acceptable product within the allocated budget. We followed two guiding principles: (1) focus on the biggest users, that is, oil, gas, coal, and aggregates, and (2) if a county has no operations of the previous category, check for any minor mining activity. Several methodologies have been used in the past at the national and state level. Norvell (2009) and TWDB (2003) tried to link economic activity and water use to a black-box approach without including the detailed processes specific to each mining sector. This approach cannot predict groundwater/surface water split.

Another approach calls for the use of water-use coefficients. These coefficients, intensive in nature, are obtained by taking the ratio of two extensive values for a few facilities: (1) water use and (2) commodity production that results in a unit of gallons per weight or volume of the commodity. In a second step, the overall water use for all facilities of that type is computed by applying the water-use coefficient to the overall production for each facility, each county, or across the state. This approach has limitations because 1) the few facilities used to develop the coefficients may not be representative of the overall industry (they are typically chosen because they provided information not because they are representative), and 2) a large state, such as Texas, has considerable climate differences which make it more difficult to apply a single, general coefficient to all facilities. USGS presented in a recent report its approach to estimating mining water use at the national level in 2005 (Lovelace, 2009) and, for the most part, it made use of water-use coefficients. Unfortunately, the specific water-use coefficients are not publicly available. Lovelace (2009, Table 1) gave a broad range in the following general categories that are applicable to the whole nation: metal mining (140 to 1,567 gal/st), coal mining (50 to 59 gal/st), and mining and quarrying of nonmetallic minerals except fuels (30 to 997 gal/st).

This second approach does not work for oil and gas water use because many oil and gas areas use only water to drill and stimulate wells, usages not directly related to hydrocarbon production. A third approach consists of actually obtaining the information directly from the facilities/operators responsible for most of the water use. This approach is particularly effective when databases contain the information, such as in the case of shale gas and oil.

3.1 General Sources of Information

The TWDB Office of Planning obtains material for its projections by regularly collecting data through annual water-use surveys (WUS—http://www.twdb.state.tx.us/wushistorical/) for input into water planning. In Texas, water planning is done through 16 Regional Water Planning Groups (Figure 8; http://www.twdb.state.tx.us/wrpi/rwp/rwp.asp). Data collection by TWDB goes back >50 years to 1955, although the legislature increased the impetus when Senate Bill 1 was passed in 1997, requiring State and local governments to become better informed on how water was utilized in their jurisdiction. Sending back the requested information to TWDB is voluntary, however. TWDB then extrapolates the incomplete information to the whole state. BEG has access to the data collected by TWDB, and the latest water-mining-use information is available is 2007. Unfortunately, the response rate for a given year is low, although through the years many companies have returned surveys.

Overall, during the course of this study, we acquired both soft and hard data. Soft data, such as guesstimates of the future direction of the different mining sectors, were attained mostly through (1) discussion with professionals from the industry and (2) by perusing the web (USGS, EIA, etc.) and other sources of reports and papers (for example, Powell's *Barnett Shale Newsletter*, a weekly newsletter providing information on various gas shales in the U.S.; the *Oil&Gas Journal*; *Energy Intelligence Natural Gas Weekly*; *Texas Drilling Observer*; SPE onepetro database articles, *Fort Worth Oil and Gas Magazine*, and DOE news alerts).

The large amount of knowledge accumulated about production from shales has not fully made its way to the peer-reviewed literature yet, thus requiring us to rely on many noncitable data. As such, this project involved a great deal of interaction with workers in the field, indispensable to locating the latest source of information and to updating it to current knowledge. Fairly complete hard data on water use in the gas industry ("frac jobs") were obtained from IHS Energy, a private vendor compiling all information filed by operators to the RRC (as well as many other governmental entities around the world), and putting it into a format easy to search and retrieve. We also directly used the query tool available from the RRC website. However, not having direct access to the database for custom queries was a handicap. RRC aggregates its data by fields, counties, or districts (Figure 9).

Data on water use for drilling and waterflooding are much harder to obtain because operators do not have to report their water use as such. The latest thorough data collection of water use in the oil and gas industry was the 1995 RRC survey (De Leon, 1996). We updated these 15-year old data by contacting a trade association, TXOGA, and by surveying operators in West Texas, the area with the most waterflooding in the state, which helped constrain current and future water use.

Data on the coal industry were obtained through a survey of Texas coal operators (~100% response rate) and a follow-up with them, consulting with RRC and collecting information from its paper files. Information about the aggregate industry was obtained through surveys we requested from two trade organizations (TMRA and TACA) and discussion with selected operators. For all other operations, we did not gather additional information but relied on published information. Exceptions were a few clay operations, as well as a few uranium operators affiliated with TMRA, from whom we also received survey results. The search was guided by previous work from the TWDB, as well as by published and unpublished documents.

We also sent out, with modest success (see Appendix D), a questionnaire to various water governmental entities for information on mining activities in their jurisdictions. Apart from those mentioned in the body of this report, very few Groundwater Conservation Districts (GCDs) have accurate knowledge on the amount of water used in their areas in the mining category unless the information is readily available (for example, lignite operations) (see Appendix E for details). Figure 10 displays a current map of GCD locations, with active and inactive mine locations superimposed.

3.2 Definition of Mining Water Use for the Purpose in this Report

For consistency with previous estimates and comparison with other studies, we followed the standard classification for economic activities. According to the Standard Industrial Classification (SIC), mining industries are given the following four-digit codes:

Major group 10 (1000 to 1099): metal mining

Major group 12 (1200 to 1299): coal mining
Major group 13 (1300 to 1399): oil and gas extraction
Major group 14 (1400 to 1499): mining and quarrying of nonmetallic minerals, except fuels

These major groups also include *beneficiation*. Operations that take place in beneficiation are primarily mechanical, such as milling–crushing and grinding, washing, dust suppression on service roads, and outdoor machinery. Manufacturing, which includes chemical and more involved processes, is represented by major groups 20 to 59. Major group 32 consists of stone, clay, glass, and concrete products, including cement (3241 is hydraulic cement) and clay products. SIC codes have been superseded by NAICS codes but are still widely in use. The more recent six-digit NAICS code defines "Mining, Quarrying, and Oil and Gas Extraction" as Sector 21. Beneficiation of mined material is included in this category that also includes the following groups: 211xxx oil and gas extraction, 212xx mining (2121xx coal mining; 2122 metal ore mining, 2123 nonmetallic mineral mining, and quarrying), 213xxx: support activities for mining. Similar to the SIC classification, several potential mining products are in an ambiguous position: clay and refractory products, cement (SIC3241 hydraulic cement and 3273xx cement and concrete product manufacturing), and lime manufacturing.

Introduction to the SIC3241 group (hydraulic cement) on the official website states: "*When separate reports are available for mines and quarries operated by manufacturing establishments classified in this major group, the mining and quarrying activities are classified in (...) mining. When separate reports are not available, the mining and quarrying activities (...) are classified herein with the manufacturing operations.*" In this report, we have included small clay pits but have not included cement raw materials, limestone and clay, that are sintered together to make the clinker that will be finely ground to become the main constituent of portland cement. Some cement-producing facilities just grind the clinker and include additives without performing any quarrying activities. More generally, concrete plants of the *ready-mix* or *central mix* type are not included in this study. A rough calculation yields ~125 gal water/st of cement to make concrete or, equivalently, 30 gallons of water per short ton of aggregate. Including concrete manufacturing in the water use of aggregate quarrying operations would inflate mining water use. This distinction seems logical on paper but may be hard to apply in the field, where different water uses may not be tracked separately, or worse, water use for the whole process may be reported as mining. Similarly, asphalt plants and brick manufacturing plants are not included. We also excluded as much as possible water used to convey materials from extraction sites to offsite processing facilities. Thus, water for slurry pipelines and tank farms was not classified as mining water.

The opposite issue occurs with gas plants and other oil and gas facilities located not far from the extraction wells. They are listed with a mining code (SIC 1321) and are excluded from this study. Similarly, some other operations are listed with a mining SIC, for example SIC1459 (clay, ceramic, and refractory minerals), but most of the water is used in manufacturing, not mining activities. The matter can worsen if some of the raw material used in the plant is not locally extracted.

Another important issue is dewatering, especially of coal mines. In agreement with TWDB, we considered aquifer dewatering as consumption because the water is no longer available for other aquifer users. It should be noted, however, that the water could still be put to beneficial use when discharged to local streams and rivers. In other words, some mining operations could be considered as net producers of water, not as users of water, for planning purposes. And yet the

position taken in this document is that, as long as there is no directly specifically targeted user, the water must be counted toward consumption.

3.3 Methodology: Historical Water Use

Historical water use was computed using direct data if available (for example, shale gas, coal), with the potential problem of completeness (missing facilities), in which case extrapolations were performed. In other cases, water-use coefficients were used. We used the year 2008 as the reference year because at the beginning of this work, not all 2009 data were yet available and because the year 2009 is likely not representative, owing to the economic slowdown.

3.3.1 Oil and Gas Industry

3.3.1.1 Gas Shales and Other Tight Formations

Gas shales are called resource plays in the sense that most wells will yield some gas over a large regional area, as opposed to conventional oil and gas production that needs to tap actual reservoirs of limited spatial extent (Figure 11). We extracted data from the IHS database relative to all fracing operations from the origins of the technology. We collected names of plays typically fraced by consulting BEG researchers with expertise in this field. Collecting all historical information allows for an understanding of the evolution of the technology—from small-scale fracing to improve permeability around the well bore in relatively permeable oil and gas formations, to medium-scale operations on tight gas to generate fracture permeability required to produce gas, to recent large-scale operations on shales (to recover mostly gas but also more and more oil).

We determined the plays with active frac jobs by downloading from a database provided by a private vendor: IHS Energy. The ultimate source of most of the information was forms submitted to the RRC by operators, but with the added advantage of a powerful querying tool. Before drilling a well, including recompletion, operators must apply to the RRC for a drilling permit (form W-1). Once completed, operators submit a W-1 form (for oil-producing wells) or G-1 form (for gas-producing wells). The two latter forms contain information about well stimulation, including slick-water fracing.

We compiled all wells completed in the 2005–2009 period (5 years) and then selected wells with water use >0.1 Mgal. This threshold is somewhat arbitrary and was used to distinguish true frac jobs from simple well stimulation by fracing and acid jobs. This approach is better than relying on operator classification of acid vs. frac vs. some other IHS category because our experience shows this method to be unreliable. We then compiled all plays with at least one frac job in that period and returned to the IHS database to obtain all wells fraced in these plays (including earlier than 2005). Further processing is detailed later. An additional download of the 2010 data was done in November 2010 to identify recent trends.

Nicot (2009a) and Nicot and Potter (2007) (also in Appendix B of Bené et al., 2007) detailed one of the methodology approaches followed in this current work as applied to the Barnett Shale. Appendix B presents the successful postaudit of the projections made during the 2006–2007 Barnett Shale study. Because of budget constraints, it is not possible to reproduce the finer level of granularity achieved in the previous study, but the general methodology stays identical: (1) gage the eventual level of drilling (and upper bound of ultimate water consumption) at the end of the play history by estimating reserves and prospectivity and (2) distribute water use through time by estimating rig availability for the next few decades and by applying time-varying

correcting factors. Many papers emphasize that each play is different and that even wells in close proximity show widely different behavior (Matthews et al., 2007; Chong et al., 2010; King, 2010). However, we assume that, at the county level, most of these differences average out and that it is appropriate to use averages.

The whole process relies on having accurate historical data, which, in this work, are obtained from the IHS database (*header* and *test treatment* options). The first step of the processing is to check the data and fix possible typos (wrong units, additional or missing zeros, etc.). Not paying attention to the typos (generally <10% of the selected portion of the database) could decrease or increase individual well-water use. Typos artificially increasing water use represent the larger risk. The general approach to achieving this goal was to compute proppant loading and water-use intensity for each individual well (not individual stage).

Proppant loading is computed by summing up the amount of proppant mixed and the amount of water used and taking the ratio. Field units are pounds per gallon (ppg or lb/gal). An acceptable value is near 1 (0.5 to 2, e.g., Curry et al., 2010, p. 3; our own statistics). This parameter has to be used with caution because, in past treatments, proppant loadings were at least twice as high but with a smaller water volume. Hamlin et al. (1995, p. 9) mentioned 50,000 to 70,000 gal of gel and 100,000 to 120,000 lb of sand for Canyon Sands in the Val Verde Basin of West Texas. Dutton et al. (1993, p. 45) cited a typical treatment in the Cotton Valley sandstones of 0.4 Mgal and 1.7 million lb of sand. They also indicated (p. 79) that 150,000 gal of x-linked gel and 450,000 lb of proppant were appropriate for the tight sands of the Vicksburg Formation of South Texas.

Water-use intensity is computed by dividing up total amount of water used by length of the productive interval, either vertical length for vertical wells or total lateral length for horizontal wells. Lateral length can be computed from two techniques that generally agree: distance between surface location of the wellhead and bottom-hole location and/or length of total driller depth minus true depth (Figure 12). These are approximations that work well as long as they are applied consistently across a play and as long as most wells are constructed similarly. The so-called directional wells present a challenge, but they are not very numerous in the IHS database and are folded into the horizontal-well category.

Total water use, total proppant amount, water-use intensity, or proppant loading out of the common range create additional scrutiny for that particular frac job. The process is semiautomated because there have been tens of thousands of frac jobs across the state in the past few years. Building a histogram or using the filter feature in Excel are the two ways used to catch these outliers. Many errors can be caught by looking at the consistency of metrics. The decision is then made to fix an obvious typo (for example, barrel unit instead of gallons or tons instead of pounds or an extra zero for water a figure that matches expected water intensity and proppant loading only when it is removed). If no fix is evident, the frac job receives the median water use for that play and year(s). Frac jobs with missing water use are also treated by estimating what they should be from the proppant amount and the median proppant loading for that play and year(s). If neither the water volume nor the proppant amount is given (can be as high as 30% of the data set for a play), the frac job receives the median water use for that play and year(s). The focus is more on the median than on the average, which can be heavily biased (Nicot and Potter, 2007).

Once the selected data set were cleaned up, we used in-house visual basic scripts within Excel to build various histograms and plots for each play: (1) location map and geological information as available, (2) plots of historical number of frac jobs per year in combination with percentiles of water use (for vertical then horizontal wells), (3) comparison of distribution of vertical vs. horizontal wells through time, (4) histogram of water use per vertical well, (5) histogram of water use per horizontal well, (6) histogram of water use intensity for horizontal wells, (7) histogram of proppant amount, and (8) histogram of proppant loading. Historical plots do not include wells with no water-use value, but those wells are added to the 2008 reference year, assuming a median water-use value.

A major assumption is that all makeup water is fresh. Typically, higher TDS water (mostly because of calcium) will increase friction-reducer demand, one of the additives. Hayes (2007) discusses the industry requirements in terms of TDS and ionic makeup. A brackish water (or even saline water, for example, from the underlying Ellenburger Formation in the Barnett Play) could be used if the pressure required to frac the shale is not too high (translating into lower pumping rate and, consequently, less friction reducer). Some higher-TDS water (from reuse of flowback) can be used too, but it is accounted for in the use of a recycling coefficient.

3.3.1.2 Waterflooding and Drilling

RRC neither systematically compiles information on waterflooding and similar recovery processes nor does it collect data about drilling-water use. RRC does post information about injected fluid volumes, but there is no systematic information on the nature of the fluid. Most is likely water, but often there is no indication of the TDS of the water, nor is the groundwater/surface water split well constrained. Fresh-water injection wells need to be permitted as such. Form H-1 asks for the type of injected fluid (saltwater, brackish water, fresh water, CO_2, N_2, air, H_2S, LPG, NORM, natural gas, polymer, and others). For waters other than saltwater, the form requires the applicant to provide information on the source of the injection water "*by formation, or by aquifer and depths, or by name of surface water source*" (fresh-water questionnaire or form H-7) and to demonstrate that no other source water of adequate quality is available nearby. A companion form (form H-1A) requests maximum daily or estimated daily injection rates of each fluid type (including fresh and brackish water when appropriate). Actual water use is reported on form H-10 (http://webapps.rrc.state.tx.us/H10/h10PublicMain.do). A UIC query (http://webapps2.rrc.state.tx.us/EWA/uicQueryAction.do) also provides useful information about individual wells, although no breakdown in type of injected fluids. In addition, the regulatory focus is on the total volume injected and the pressure rather than the type of fluid injected. Experience has shown that H1 forms are only of little use in estimating fresh-water use; rates provided by the applicant largely overestimate actual rates.

Other researchers have also tried to collect waterflood information. Lovelace (2009), in a USGS summary of the approach used to estimate 2005 oil and gas water use across the nation, presented the assumptions made to develop the final figures including into his fresh and saline categories. (1) all water is groundwater; (2) if several water types are indicated in the H10 form, they are assumed to be of equal volume; and (3) because injection volumes are not provided for individual wells, all wells were assumed to contribute equivalent volumes of water. However, the 1995 RRC study (De Leon, 1996) invalidates some of those assumptions; a significant fraction of the water is surface water.

In the end, to gather information about waterflooding, we decided to send quantitative survey forms to ~25 leading oil-producing companies in West Texas, where waterflooding and EOR

operations are concentrated (Galusky, 2010). This mailing was followed up with telephone calls and e-mails, and we communicated to them that all of the information and data that they provided would be held in strict confidence by Texerra/P. Galusky, who would submit only an aggregate compilation and summary of key findings in its report to BEG. Additional data and information on drilling activity, oil production, and related parameters were obtained from various publicly (internet) available and private (commercial) data sources.

Drilling-water use is generally not reported, and waterflood reporting combines all water sources from fresh to saline. A logical approach is then to collect information from operators. Drilling-water-use information was collected through informal discussions with practicing field engineers.

3.3.2 Coal/Lignite

Determining the amount of water used within the coal mining industry proves to be a complicated task because no entity currently tracks consumption; however, all coal mine operators must report total pumping rates to the RRC as a requirement for their mine operating permits under Title 16, Part 1, Chapter 12 of the Texas Administrative Code. When a mine operator applies for a new permit, estimates of current conditions and future drawdown must be provided to allow the RRC to determine allowable pumping rates. Once mines are in operation, operators must report their drawdown and pumping rates quarterly for the first 2 year, and then once every year following the 2-year period. The RRC does not restrict the amount of water to be pumped. The agency simply tracks pumping rates and requires documentation of the drawdown impact of mining operations on the surrounding areas (T. Walter, RRC, 2009, personal communication). Dewatering and depressurization totals were collated from each mine from RRC public records with the cooperation of Tim Walter, as well as results from the survey sent to each operator.

To help in the process of collecting data, in-depth literature searches and discussions with industry experts were conducted to help us decide on the best route for determining withdrawal and consumption estimates. We concluded that estimates for specific mining activities, such as hauling or dust suppression, vary for each active mine, depending on climate, location geology, production techniques, and other factors. Therefore, it would be necessary to analyze each mine individually. Fortunately the number of facilities is small, and all of them are large and well documented. We launched a survey in coordination with the Texas Mining and Reclamation Association (TMRA), which was very successful (~100% response rate).

An important question was whether to include pit-dewatering volumes into water consumption/withdrawal. Pit water originates from rain falling into the pit and being captured by its drainage area, as well as seepage from the overburden. The latter can be minimized but never eliminated by pumping groundwater from the formations to be removed before mining. Many mines divert runoff and pit water from precipitation into retention ponds and use it, for example, for dust control. For consistency with the approach followed in the aggregate category, we did not include pit dewatering (strictly defined) in water use.

Aquifer depressurization also lacks the clear-cut classification of some other water uses. Although the amount pumped for depressurization represents a net loss to the aquifer, the water is available for other uses, in particular environmental flow. In addition, in at least one mine, depressurization is put to immediate beneficial use when some wells are turned over to a water supply company (T. Walter, RRC, 2009, personal communication). This amount of water is not

counted toward mining so as to avoid double-counting when merging all water uses, although it could bias water-use coefficients (they are not, however, used for coal in this study).

3.3.3 Aggregates

The approach for aggregates is different from that for oil and gas, about which relatively little is known or for coal/lignite, about which a complete data set exists. TWDB already has a working database from past water-use surveys. Various other reference sources and data sets were examined in an effort to determine whether available information could be used to further validate the TWDB water-use estimates and/or to refine our estimates at the county level. Resources examined include

- USGS
- MSHA
- TWDB
- TCEQ
- Interaction with and web search of the largest producers in the state (Martin Marietta Materials, Inc., Vulcan Materials, Inc., and Capitol Aggregates).

Furthermore, we recognized that although most aggregate operations recycle or reuse a large proportion of the water used in their processes, water-use data sometimes reflect the full volumes used and do not account for the recycled volumes. Such an uncertainty may result in inappropriate inflation of the values used for planning purposes. This report also attempts to assess the availability of additional information that may differentiate between water used in aggregate mining and that actually consumed or lost in these processes. A significant effort was made to conduct a survey in coordination with TMRA and TACA to obtain water-use and water-consumption data for a sampling of representative member companies and facilities across the state (survey questionnaires in Appendix D). Despite the cooperation of the two associations and multiple attempts to encourage participation, only seven companies of the many companies contacted responded to the survey request. They provided information for 27 separate facilities with information on location, production, water use, recycling rate, and source water.

These database reviews and survey results were analyzed and compared in order to supplement the information obtained by earlier surveys and planning documents. Results of the survey were highly variable, with some data tending to validate information obtained from earlier work by other agencies and some data suggesting significant differences. The survey highlighted the difficulties in using this approach to gather information on the industrial mineral mining sector. Some of the factors that may have influenced the response include the number, diversity, and relatively small size of many of the mining operations; the concern expressed by many in the mining industry of disclosing competitively sensitive information; the lack of available personnel to compile or calculate data; and the lack of regulatory requirements to collect and report requested information.

Issues we had to overcome or mitigate included (1) information on the types and numbers of industrial mineral mining facilities in Texas obtained from the Mining Safety and Health Administration (MSHA)—681—differed significantly from data from TCEQ—3,125 and (2) water-consumption coefficients, expressed in terms of gallons per ton of product extracted (gal/t) or gallons per dollar of production output (gal/dollar), which have been developed to estimate current and future demands on the basis of population growth or financial forecasts. The coefficients for washed crushed-stone mining derived from the survey were significantly

different from those previously determined by either the USGS or the TWDB, whereas the coefficients for construction sand and gravel operations were similar to previous estimates.

Directly useful data in our possession were

(1) Production and water-use information for a few facilities (27) from the BEG survey;

(2) Water-use information from TWDB WUS survey dating back from 1955, although only recent information was used (26 facilities with some overlap with the BEG survey);

(3) List and locations of facilities trying to limit the potential problem of having listed the location of the company headquarters possibly located in a county different from that of the quarry/pit;

(4) Generic industry water-use coefficients from other studies;

(5) Water-use information at the county level for all mining activities from USGS (year 2005); it is thought that the fresh-water-use data include mostly coal and aggregates;

(6) County-level population information from TWDB projections;

(7) Annual state production in 2008 (153 million tons crushed stone and 87.7 million tons sand and gravel) and earlier years (for example, 136 and 99.5 million in 2006, respectively)

As noticed by earlier workers, there is no clear correlation between production and water use, an observation again confirmed by the BEG survey. If that were the case, we could simply infer water use from production. However, neither production nor water-use figures are readily available. Actually, production figures are available that are aggregated only at the state level and do not result from direct data compilation. USGS collects production information and does it through surveys (and information collected from state agencies) but is never able to collect comprehensive data and has to rely on extrapolations. TWDB is focused on water use and does similar regular surveys but with limited success. Some companies consistently and voluntarily report their water use, whereas others are less straightforward. Regional Water Planning Groups (RWPGs) (Figure 8) know the reality of their region but are rarely focused on mining, which is typically a small fraction of total water use, and often relies on TWDB figures. Similar to previous USGS and TWDB reports, we elected not to link the data we present later in this report to individual facilities.

We used a two-pronged approach to assess aggregate water use:

(1) When water-use figures are known for a given county, they are used.

(2) For counties with only partial or no information on water use, we rely on estimated production combined with an estimated water-use coefficient. Water-use coefficients are computed from (1) a BEG survey and (2) generic coefficients from previous work. Estimated production at the county level is computed from local population and number of facilities. A higher number of facilities in a county relative to the population suggest a particularly favorable geology and a higher production per facility.

These detailed steps were used for crushed-stone water use:

(1) Derive statistics from BEG survey results.

(2) Compare with TWDB WUS and USGS county-level mining-water use.

(3) Compare with generic aggregate water use.

(4) Determine counties with crushed-stone facilities. Sort into two types: (a) of primary importance and listed on the NSSGA/USGS database, potentially deserving markets up to 50 miles away and lasting to the end period of this study and beyond or (b) of secondary importance and listed only on the MSHA database with only local subcounty impact and likely ephemeral in nature (a few years).

(5) Distribute crushed-stone production throughout the state using facility list from NSSGA/USGS; county-level production is anchored by the few counties for which production is known and scaled from the state production according to local population (more details on the mechanics of this in the methodology section for future water use—Section 3.4). Counties with facilities listed in the NSSGA/USGS directory are assigned the population of that county and that of surrounding counties; counties with facilities solely in the MSHA database are not included (Figure 13).

(6) Apply average/generic water use for those counties with no information. Given the large range in water-use coefficients, although likely relatively accurate at the state level, estimated county-level figures may diverge from actual figures if their facilities are more water conscious or less efficient than those of the average facility. USGS uses employment data from MSHA to estimate size of facility. We confirmed the size of some facilities, especially those with seemingly high water use, through Google Earth. Combined with other sources of information, Google Earth could be a good tool for estimating more accurate water use, especially through time, using the historical imager option. Excavation changes through time would help put bounds on production, and pond size and other water features would suggest water use.

Water use in the sand and gravel category follows the same approach except that all production is assumed to be consumed locally within the county; that is, population of surrounding counties does not figure into the calculation. Again, note that we did not include cement or concrete facilities (as far as we can tell by the description given in the databases) in this study. They are part of manufacturing, even if they have quarry operations onsite.

3.3.4 Other Mined Substances

Methodology for other mined substances is done on an ad hoc basis but mostly it is done by collecting information from TWDB WUS. We also collected direct information from some uranium and clay facilities with the survey through TMRA (Appendix D). Specific details are given in the current water-use section (Section 4.5). We included industrial sand operations in the "other" category, although they bear many similarities to the aggregate industry, although the much higher water use coefficient sets them apart.

3.3.5 Groundwater–Surface Water Split

Accessing the source of water used is difficult in most cases. Water use is well documented for some mining-industry segments, such as coal mining, but it varies widely for oil and gas and aggregate-mining segments. Historically the trend in the state has been to rely more and more on surface water. The best source of information is direct surveys, but even knowledge of current sources may have little predictive power. For example, in Louisiana, Haynesville shale frac water initially from the Carrizo-Wilcox aquifer (Hanson, 2009) has switched to alluvial aquifers and, mostly, surface water (Red River) after suggestions by the Louisiana Department of Natural

Resources. And treated wastewater from a paper mill in northern Louisiana has recently been added to the mix of water sources used in the play.

We provided information about the groundwater– surface water split as it became available during the data-collection process but did not try to generalize to the whole mining industry.

3.4 Methodology: Future Water Use

What are the substances currently being mined? How much longer will they be mined? Do any of the substances mined in the past have a credible chance of being exploited again, both in terms of substance and location? What are the new substances that could be mined in the future? Some of these questions are not easy to answer, but overall the main driver of water use in the mining sector is mostly (1) population growth and (2) economic development, especially concomitant energy demand nationally. Population growth relates to resources consumed within the state (aggregates, coal), whereas economic development impacts all substances, including those mostly exported out of the state either in their raw form or transformed. A project such as this includes many levels and types of uncertainties. A tentative comprehensive sampling despite the appearance of completeness can overlook several facilities, although not any one large facility. Operators can make honest mistakes when reporting information or include water-use categories that should not be included. Even more uncertain is extrapolating for long periods of time from a short period of time of a few years, such as for shale gas and oil. Long-term energy projections do not have a very good track record (Figure 14, Figure 15). Figure 14 provides an example of the difficulty of making projections. A natural tendency is to extrapolate trends; projection of U.S. gas consumption made in 1970 is a simple extrapolation of the strong trend of the previous year. Projection for 1972 follows the same model with a smaller growth rate. Year 1974 projection continues to extrapolate, although one of the marking events, energy-wise, of the second half of the 20th century occurred in 1973. Figure 15 demonstrates that, even in the midst of a known energy-paradigm change, shale-gas production (and, by extension, water use) was consistently underestimated. Hindsight or postaudits are a great way to improve the reliability of such scenarios. BEG published an analysis of water use in the Barnett Shale using data from 2005 (Nicot and Potter, 2007), and a comparison to actual water use is presented in Appendix B. The overall conclusion is that projections match recent data but only because of the recent economic slowdown.

We debated having deterministic vs. a range of projections (for example, high, medium, low) and concluded that we would focus on a ***single best-guess scenario,*** with the understanding that uncertainty increases with annual horizon. Although working on a 50-year horizon helps in an understanding of heavy trends, we tried to focus on the next 10 years, the timeframe in which this work could have the most impact. Another concern is higher-frequency changes, again mostly applicable to shale gas, such as the current economic slowdown. A long-term decade-level horizon makes it easier to ignore these high-frequency cycles and to focus on long-term trends. The downside of such an approach is that projections may not be correct in the rate of change of water use from one year to the next but they may be more accurate cumulatively.

Post-mortem analyses of long-term projections show that they often deviate from actual figures because of unpredicted events. A case in point is the rapid development of water-intensive gas production from gas shales. Such events are by nature unpredictable and, although we can develop scenarios, their multiplicity quickly becomes unmanageable: what year does it begin, how fast does it develop, is it permanent or transitory, what is the magnitude of impact, etc.?

Including the uncertainty of abrupt changes in water use, projections would render them meaningless, so our approach has been to ***assume that current trends will continue***. In contrast to abrupt changes, long-term shifts in water use, particularly in the energy sector, can be better tackled. As discussed previously, a large fraction of the mining output is related to energy production (oil, gas, coal). King et al. (2008) discussed future directions of the energy sector in Texas as it relates to water use. For example, development of nuclear power would merely transfer water use from the mining category to the power-generation category, as well as move it to different counties and regions, as would a shift from coal to natural gas. This project does try to predict the unpredictable but always assumes a slow rate of change, such as gas slowly overtaking coal as the major electricity-generating fuel in Texas or the rise and decline of gas production. However, most gas is exported out of state and, because of a projected overall increase in energy consumption, is not denting water use by the coal industry.

Next, we discuss the relationship between three of the major water users in the mining industry: oil vs. gas and gas vs. coal. Oil in terms of energy has always been at a premium relative to gas (for example, Kaiser and Yu, 2010), being sold at a higher price for the same energy content. Natural gas, being a gas at surface conditions, requires more advanced technologies for it to be transported to areas of consumption. The year 2010 has seen a rush toward the oil window, thought to be more profitable, in some so-called gas shales but more accurately described as liquid-rich shales, such as the northern confines of the Barnett Shale or the western section of the Eagle Ford. Such a trend of operators focusing on oil rather than gas, if it persists, will impact water use at the county level, if not at the state level. This focus on oil is analogous to a smaller-scale shift in oil and gas operators' thinking. In this project, we assigned a slightly higher weight to these oil window/combo counties, but on the whole we consider this oil focus a short-term deviation. Another example concerns some gas plays very much in the news 2 or 3 years ago, such as the Pearsall Formation in South Texas or formations of the Palo Duro Basin in the Texas Panhandle, that have since disappeared from the radar, while others such as the Haynesville and, even more so, the Eagle Ford, have exploded in terms of activity. In this ever-changing environment, it is challenging to predict where the gas industry will be active 5 years from now. Another single event with possible repercussions, particularly in terms of legislation, is the Macondo well. On April 20, 2010, a grave accident occurred in the deep offshore Gulf of Mexico. Responding to a likely increase in regulatory scrutiny and, therefore, increased cost, many operators, particularly independents, may redirect their efforts onshore, especially to unconventional oil plays (the Eagle Ford, Barnett Shale oil windows).

Coal and natural gas are used mostly for energy production. Both industries are optimistic about their futures. The Texas energy portfolio consists of mostly coal, nuclear, natural gas, and others, including oil and renewables. King et al. (2008), looking at energy use in Texas by 2060, assumed an annual electricity growth rate of 1.8% in business-as-usual scenarios. These workers also investigated a low-energy-usage case. They described four scenarios combining high/low natural gas prices and implementation (or not) of carbon capture and storage (CCS). In both high-natural-gas-price cases, coal use expands and natural gas use stays steady. However, if natural gas price stays low, coal share decreases even if overall energy consumption decreases. If, in addition, CCS is made mandatory through a hypothetical cap-and-trade or carbon-tax legislation (to deal with climate change, the advantage of natural gas relative to coal is that it releases less CO_2 per unit energy than coal), coal share in the energy mix decreases even faster. However, EIA (2010, p. 79) suggested that lignite production may increase in Texas. Coal mined in Texas is always used locally (mouth-of-mine coal-fired power plants), but a significant

fraction of the gas goes into the general market and is exported out of state. For example, 45+% of electricity consumed in the state is produced by natural gas, for a total of ~200,000,000 MWh (equivalent to 0.68×10^9 MMBTU, with 1 MMBTU = 0.2931 MWh). In 2009, natural gas production in the state was 7.66×10^9 Mcf (equivalent to 7.66×10^9 MMBTU, with 1 Mcf =1 MMBTU). Major growth in other parts of the world may boost the gas industry for export, and development of LNG terminals in Texas or the glut of the gas commodity may keep the prices too low for its development to have a major impact on water use (averaged over decades). An authoritative recent study on natural gas (MIT, 2010) suggests that use of natural gas will expand and an earlier study by the same organization (MIT, 2007) acknowledges that coal use is likely to increase overall even if its relative share in the energy mix decreases.

To develop our own understanding of those issues, we collected material from Washington-based think tanks, attended specialized conferences (Nicot, 2009a; Nicot and Ritter, 2009; Nicot et al., 2009; Hebel et al., 2010; Nicot and McGlynn, 2010; Ritter et al., 2010) and discussed the matter with experts. Overall, we decided to use a middle-of-the-road scenario, and because of the mixed signals received from different entities about coal consumption, either up or down, we assumed that it stays at its current level with no sharp increase or decrease in absolute figures (but decreasing in the state energy portfolio), in agreement with discussions with coal producers. Texas gas production is controlled by external factors independently of population growth, whereas aggregate production is controlled entirely by population growth.

Judgment on future water use of nonfuel substances is either more straightforward (aggregate) or less consequential in terms of total water use. Information about future water use was determined not only through direct results of forward-looking survey questions and general understanding of the commodity, but also by scouring Regional Water Planning Group (RWPG) reports. Texas is composed of 16 RWPGs, each of which is charged by law to project water needs and water sources for its own area and to submit information for incorporation into the state water plan. Water Plans (TWDB, 2002, 2007; http://www.twdb.state.tx.us/wrpi/data/proj/demandproj.htm for year 2007) present projections but in general are aggregated at the regional planning level.

3.4.1.1 Gas Shales

The general philosophy of the approach is top-down, that is, distributing estimated overall oil and gas production, as well as water use, across counties, rather than a bottom-up approach, in which a time-consuming and hard-to-get detailed compilation of fields, formations, and local input would be aggregated to deliver county-level figures. This section is untitled gas shales but includes the oil window generally located updip of gas shale proper (liquid-rich shales). As far as water use is concerned, well stimulation does not seem to be approached very differently. Quantitative approaches to future water use in shales fall into two broad categories: (1) production-based approach and (2) resource-based approach. The latter was applied to the Barnett Shale by Nicot and Potter (2007) and Nicot (2009a). In this report, we followed both approaches simultaneously, making sure results were consistent.

A ***production-based approach*** follows five steps, which are further described later in this section:

(1) Determine with the help of BEG experts (or gather from the literature) the total amount of gas/oil contained in the shale, as well as the recoverable fraction and the estimated annual production level. This step also involves recognizing the boundaries of the play.

(2) Decide on (or gather from the literature) the average Estimated Ultimate Recovery (EUR) for a single well.

(3) Compute the total number of wells needed.

(4) Apply the average water use per well (computed from historical data, we have a good handle on water use of many individual wells across many gas plays in the state, as detailed in Section 4.1), possibly corrected by factors accounting for technology advances and increased recycling and, perhaps, additional rounds of well stimulation. Well count for the first few years is estimated, given rig availability, which after a few years becomes irrelevant because the service industry will respond to needs by constructing them.

(5) Distribute through time (expected life of the play) and space (county level) as a function of prospectivity and other parameters. This step is the most uncertain and open to interpretation.

A ***resource-based approach*** follows four steps:

(1) Gather historical data in terms of average well-water use and average well spacing.

(2) Estimate ultimate well density across the play; it is a function of factors, such as geological prospectivity (for example, within play core or not, shale thickness) and cultural features (urban/rural). In this step, ultimate boundaries of the play are identified.

(3) Compute total number of wells needed.

(4) Distribute through time and space, constrained by the assumed number of drilling rigs available (see earlier comment).

As an entity whose strength is applied geology, BEG had the opportunity to develop its own assessment of shale-gas reserves in Texas. Gas accumulations can be biogenic, in which microbes biodegrade organic matter to release methane, or, as in all Texas shale-gas plays, thermogenic. Thermogenic gas is produced by the natural cracking of complex organic molecules into oil and gas, owing to an increase in pressure and temperature, as well as sufficient time at required depths. The deeper the conditions (without some limits), the more advanced the cracking of the organic matter, whose ultimate fate is methane. Some shale plays contain only gas (if they stay in the gas window for long enough)—an example is the Haynesville Shale—others contain both oil and gas either at the same location (a well will produce both oil and gas) in a so-called combo play (for example, the northern section of the Barnett) or spatially distinct oil and gas zones with a mixed transition combo zone (for example, the Eagle Ford Formation). There is a relationship between total organic content (TOC) and potential gas content. Vitrinite reflectance (VR) is a measure of the maturity of the evolved organic matter/kerogen: the higher its value the more likely it is to be in the dry-gas window (VR>~1.5–2). For VR values ranging between 1 and 1.5, the shale is likely to be in the wet gas window. Below a value of 1, oil is produced, whereas if VR<0.6, the sediment is immature, and no commercial accumulations are likely to be found. Combining information about formation thickness, TOC, VR, and a few exploratory wells, specialists can infer gas resources. The core area of a play is subjectively defined as the area where the most favorable combination of thickness, TOC, and VR exists. The core areas of the Barnett and of the Texas portion of the Haynesville consists of each of four counties, whereas they have an additional 20+ whole or not counties and ~10 counties considered noncore, respectively. Core counties have not been defined for other shale-gas plays,

including the Eagle Ford Formation, yet. Other known important factors are not used in this study; for example, an emerging model (S. Ruppel, BEG, personal communication, 2010) suggests that margins of shale plays are more prospective because of the influx of carbonate and other clasts with the right combination of organic matter and detrital material, making the setting more favorable.

We decided early on to rely as much as possible on published information rather than developing our own estimates. Nevertheless, knowledge of these parameters helps in determining the prospectivity of an area (county in this case), that is, its attractiveness to operators, which is obviously linked to water use as well as the boundaries of the play. Geological maps and previous drilling and production activity help in constraining the final spatial extent of the play. In practice, prospectivity (maturity, core area) is a positive number ≤1. Each county within a play is assigned a prospectivity factor (generally 1, 0.75, 0.5, or 0.3). This assignment was done in a purely ad hoc manner and in a more cursory manner than in Nicot and Potter (2007), as this parameter is softer than, for example, the play footprint and, owing to a lack of information, includes some guess work relative to where the industry is headed.

Many gas-production projections are published at the national level (EIA, USGS, PGC) aggregated from individual plays and sometimes extrapolated to prospective shale plays. Information about recoverable reserves of individual shale plays (in general, ~30% of OGIP or OOIP) are relatively easy to collect, but unfortunately there is a lack of consistency between the different figures we can gather, mostly because the methodology used to arrive at those figures is not explained in most cases. In the Future Water Use section (Section 5.1), we list figures for all Texas shale plays and explain the choice of the value we used. Another difficulty relates to the fine granularity (county level) we attempt to meet. Projections made at the national level perhaps end up being more accurate because of the low granularity of the system (many oil and gas plays), as opposed to a single state even if it is large because only a few shale plays exist. For example, Appendix B shows that careful work does not necessarily generate accurate predictions at the county level, even though they might be at the multicounty or regional/play level. We expect the same observation to be truer in this higher level study. Results at the county level may be off by a factor or 2 or 3, especially when the time component is added.

Later we focus on the production-based approach because the resource-based approach was already described by Nicot (2009a) and Nicot and Potter (2007). Some published EUR values seem to be problematic. Individual-well EUR can be estimated at 0.5 to 3 Bcf, maybe up to 10 Bcf, in highly profitable wells. Most EUR is derived from limited data, not necessarily in terms of number of wells but in terms of time frame (Figure 16). Reported average EUR values most likely reflect good wells drilled in the core area of a play and might be inflated. Water use computed from number of wells based on EUR and total recoverable gas only is therefore highly uncertain because both can vary substantially. For example, the commonly found EUR value for Barnett wells of 3 Bcf, combined with an assumed <60 Tcf of recoverable gas, yields <20,000 wells. Clearly, even taking into account that many of these wells are vertical wells with a lower EUR, more wells will be drilled in the Barnett. The very first well drilled in the core area of the Barnett in 1982 has produced 1.7 Bcf so far (PBSN, Nov.1, 2010).

Therefore, in the Barnett, either recoverable reserves are underestimated or average EUR is overestimated; that is, production drops faster than currently projected. This report puts more weight on the latter explanation, but without negating the possibility of the former. Actually, there are voices (Shook in NGW, 2009) advocating that shale gas will not carry all the promises

put forward by operators. For example, SPEE-Anonymous (2010), Berman (2009), and Wright (2008) suggested that decline curves were too optimistic, but they seem to be in the minority. Their approach has been strongly contested by the gas industry in the literature, as well as in the field, as majors (ExxonMobil, Shell, Total, ENI, Statoil, BP) started investing in shale gas. It seems that with a diversified gas-well portfolio and a statistically sufficiently high number of wells, good producers more than make up for more numerous low-performing, uneconomical wells and render the whole operation profitable for most gas operators. In other words, the viability of a play is determined by its top producers, perhaps the top 10^{th} or 20^{th} percentiles. Note that from a water use standpoint, however, uneconomical wells and good producers consume the same amount of water during fracing. Low-rated wells may even be fraced a second time shortly after the initial frac job in an effort to improve gas production.

A typical play containing 100 Tcf of gas in place, 30% of which is recoverable, translates into 15,000 wells at 2 Bcf EUR, on average. Distributing projected production/water use through time is difficult but is the essence of this project. We relied on several sources in addition to informal information, but particularly Mohr and Evans (2010) and Mohr (2010, Chapter 6), who inventoried all relevant gas shales at the time and summarized available information on projected gas production for the Barnett and Haynesville Shales. They also provided a peak year for gas production (best guess of 2015 and 2031, respectively). Similarly we assigned a peak year for each gas-shale play, which is clearly highly uncertain. Most publications assign a peak year for gas production, which typically comes after the peak year for initial well completion. However, translation from gas production to water use requires the knowledge of the EUR and the details of the production decline curve. It has been commonly observed that production decreases from an "initial production" (IP) (Figure 16). Given the relatively steep decline from IP, new wells must be drilled to sustain production. Information received from informal discussion suggests that 3000+ new wells a year are needed to sustain production at current 2010 production rates.

A commonly circulated IP value in the Barnett is 5 MMcf/d. Overpressured plays, such as the Haynesville, have generally a higher IP—reported value can be as high as 8 or even 20 MMcf/d. More generally, individual gas-well performance is characterized by their IP, how fast they decline from the IP (decline curve), and their cumulative potential (EUR). There is some evidence that pushing production to its max IP is detrimental to the EUR, so most operators throttle production to a rate somewhat lower than the possible maximum. Doing so also makes sense economically when gas prices are depressed. A large body of literature deals with decline curves, which have been a topic of considerable interest in the petroleum industry because they help forecast future performance and production. Two broad families of these mostly empirical curves exist: exponential and hyperbolic (see for example, the classic Arps, 1945; Economides et al., 1994; Ilk et al., 2008; Lee and Sidle, 2010; Valko and Lee, 2010). The former curve model is used when the decline is linear on a semilog plot against time. We tentatively used a simplified version of the Arps decline-curve equations for hyperbolic decline, which is typically faster than exponential decline.

$$q = q_i \exp(-Dt) \quad \text{(exponential decline)} \qquad \text{Equation 1a}$$

$$q = q_i (1 + Dbt)^{-1/b} \quad 0 \le b \le 1 \quad \text{(hyperbolic decline)} \qquad \text{Equation 1b}$$

Although the parameter b should be ≤ 1 to meet model assumptions, it is often set to values >1 for tight formations (Ilk et al., 2009). This parameter is difficult to assess with the limited

information available early in the history of a well. Assuming an average well EUR, a decline curve, and a given life, we can attribute a fraction of the EUR to each year. After some trial and error, we were able to match gas production from Mohr and Evans (2010), assuming an average EUR substantially lower that the most-cited core ones and with input from the resource-based approach. Note that the chosen production model is only one among many, although a middle-of-the-road, defensible one. Exploring all possible production outcomes would entail much larger efforts than available for this study. The fraction produced during the first year is ~45% and ~25% for what we defined as an overpressured *Haynesville type* and a normally pressured *Barnett type*, respectively (Figure 17), over the 30 years of the producing life of a well. The curves displayed in Figure 17 show a drop of 75% and 60% between average production in years 1 and 2 in Haynesville and Barnett types, respectively. Figures are consistent with those presented in Jarvie (2009) that document decrease in the 60–80% range during the first year of production for various shale plays in Texas and elsewhere. Note that the decline curve is just one component in estimating water use, and, although it obviously has a large impact on the production numbers, water use is less sensitive to it, especially when the production-based approach is compared with the resource-based approach.

Spatial coverage density is an important step in the resource-based approach. Figure 19 and Figure 20 display examples of thorough coverage from multiwell pads. Horizontal-well laterals are all oriented in the approximate direction that is perpendicular to minimum local horizontal stress. Nicot (2009a) and Nicot and Potter (2007) used a range of 800– 2000 ft. Generally speaking, 16 40-acre vertical wells ($16 \times 1.7424 \times 10^6$ ft^2 = 1 square mile) translates into seven 4000-ft-long laterals with 1000-ft spacing that could be all drilled from the same pad with a much larger recovery. There seems to be a relationship between lateral length and lateral spacing (Figure 18).

A limiting factor controlling the number of wells drilled every year in a play is the number of drilling rigs available. Figure 22 illustrates a time snapshot in the distribution of drilling rigs in Texas in June 2010. Rigs typically specialize as gas or oil rigs and are binned as a function of the maximum depth they can reach and the type of well they can drill (horizontal vs. vertical), but this level of detail was not included in the study. We estimate that it takes 3 to 6 weeks to drill a vertical section and a lateral in the Barnett and Haynesville, respectively. An average spud-to-release time in the Haynesville was 44 days in early 2010 (LRNL, 2010). Nicot and Potter (2007) estimated an average spud-to-spud time of 1 month in the Barnett, which is currently down to ~3 weeks. Figure 21 demonstrates the high variability in the number of active drilling rigs. Rigs travel from one play to the next and across state lines, depending on demand and on the perceived or actual potential of a play. Figure 21 shows a rig count increasing at a rate of ~100 rigs/yr between Spring 2002 and Fall 2008, then a sharp drop, and a sharper increase rate at ~375 rigs/yr between June 2009 and June 2010. This steep rate is likely due to rigs mothballed near the new drilling sites and being put back in use quickly. As of December 2010, the Barnett Shale play had ~80 rigs, and that number has varied little since early 2009 (multiple issues of PBSN). Most of the previous year, in 2008, the rig count was at ~180 active rigs. The number of frac jobs (that is, water use) is clearly related to the rig count. Nicot and Potter (2007) underestimated the ability of operators to bring in more rigs to the state. Emergence of more efficient rigs will shorten the rotation time between drilling sites and increase the number of boreholes that a single rig can drill in a year. But again, showing the difficulty of making projections, the industry may run out of trained crews to man the rigs.

Details on recycling, refracing, and other approaches are given in Section 5.1.2. We did not try to resolve the surface water– groundwater split for future decades.

3.4.1.2 Tight Formations

Tight gas (for example, the Cotton Valley Formation in East Texas) or other tight formations containing oil (for example, the Wolfberry play in the Permian Basin) are also subject to hydraulic fracturing. The main difference between them and gas shales, from a practical standpoint, is that (1) these tight formations are conventional resources in the sense that they occur in a discontinuous manner and (2) they are not new plays and have been producing gas/oil for years or even decades for the most part. We applied the same approach to compute future water use, as was employed for the gas-shale category. The approach is particularly similar to that used for the Barnett shale, which already has significant production. At the county or field level, we examined the *burn rate* of the reserves as well as the remaining reserves. Coleman (2009) presented a recent historical overview of gas production from tight sandstones.

3.4.1.3 Drilling and Waterflooding of Oil and Gas Reservoirs

Future water use for drilling was estimated at the state level only by assuming water use for shale-gas wells as provided by the literature for several plays (Section 5.2.2) and assuming an average value for the remainder of the wells. The number of wells to be drilled in the future was computed from (1) the oil subcategory for which we used recent work by Galusky (2010) in the Permian Basin; we then applied a multiplier to account for oil production outside of the Permian Basin; and (2) the gas subcategory, for which we used results from the production-based approach for shale and tight-gas plays, and to which we, in turn, applied a multiplier to account for conventional gas production.

Water use for secondary and tertiary oil production is less dependent on the number of rigs because most of the consumption occurs after drilling and during pressure maintenance or enhanced-recovery operations. We assumed that waterflooding activities occur mostly in the Permian Basin, which is also the world center of CO_2 EOR (a WAG process is typically used, in which water is injected behind slugs of CO_2). Estimates in this category are obtained through a combination of historical data, survey results, and knowledge of the industry.

3.4.1.4 Coal

Energy makeup of the state still relies heavily on coal-fired power plants (although some of the coal is imported from out of state), with nuclear energy as a distant second. The complement comes partly from natural gas and oil. As discussed earlier, we assumed a business-as-usual scenario for the coal industry and accepted figures provided by the comprehensive survey of all operators in the state. The main uncertainty resides in the possibility that the industry will start relying on coal imported from western states to feed the coal-fired power plants instead of relying on local lignite resources. Another uncertainty is the possibility of having most depressurization water volumes captured for municipal use or other beneficial use (for example, fracing), in which case mining water use may be different but not the total water use. Such a development is not accounted for in this study.

3.4.1.5 Aggregates

If some mining activities such as oil and gas are independent of the state population because their products are not necessarily consumed in the state, others, such as aggregates and lignite coal, which have high transportation costs, are consumed mostly locally and depend more strongly on

the population level in the state, nearby counties, and economic activity. Future aggregate production (and concomitant future water use) is correlated with population growth. Population of the state is predicted to grow by 20 million people, from ~25 million in 2010 to ~45 million in 2060 (both are estimates). We used TWDB population projections, which are slightly different from those of the U.S. Census Bureau, although differences are well below the level of uncertainty brought about by other parameters.

To estimate future aggregate production we relied on extrapolation from historical data and noted that aggregate production is coupled to absolute population level, but also to its derivative through time (population growth). Numerical details of the analysis are given in Section 5.4 (future water use in the aggregate category), but we based extrapolation of production and population on their changes in the past 20 years. In 2008, the amount of crushed stone produced per capita was ~153 Mt/ 24,000,000 people; that is, ~ 6.5 ton/capita/yr. During the same 1-year period, population growth was ~0.5 million people, that is, ~310 ton/capita growth/yr. A similar analysis yields ~4 ton/capita/yr and ~200 ton/capita growth/yr for the sand and gravel category. Extrapolating solely from gross population numbers seems unrealistic. Norvell (2009) used historical data and determined that over a 20-year span (1982–2003), aggregate production was best predicted by a combination of total population and the state gross product (GDP) related to construction. Population and state GDP were both approximately equally weighted in terms of coefficients, but construction state GDP in billions is about twice the population in millions, so its weight is, in essence, higher. The report states "*coefficients indicate that on average as population grows by 1000 people, aggregate output in Texas rises by 4,800 tons (i.e., about 4.8 tons per person), and every $1 million increase in gross product for the construction industry results in an additional 5,760 tons of aggregate extracted.*" The figure of 4.8 t/capita/yr is somewhat lower than the average of our two figures, although plainly consistent with them. Given the time and budget constraints to develop this report, we assume that population growth is somewhat equivalent to the economic output variable of Norvell (2009) and other economic analyses. As a whole, additional people will need houses, highways, and other facilities at a higher rate than people already living, the state supporting the assumption that population growth has a greater impact on aggregate consumption than the population parameter itself:

$$Aggr.Prod. = 2/3 \times Pop. \times Rate1 + 1/3 \times Pop.Growth \times Rate2 \qquad \text{Equation 2}$$

The population-growth component stays at a stable absolute level because growth rate itself stays stable, whereas the population as a whole component keeps increasing in absolute value and as a fraction of the total.

Once aggregate production at the state level has been determined, we could apply water-use coefficients already gathered in the previous phase of the work to obtain aggregate water use at the state level. Difficulties arose when we tried to distribute state-level water use to individual counties. In order to limit distortions due to the impact of artificial administrative boundaries (for instance, large growth in a county next to that of the aggregate facility, as we did for current crushed-stone water use), we used a simplified radius of influence technique (county of interest and neighboring counties) to apportion water use, whereas sand and gravel production is assumed consumed within the county in which it is produced. We also assumed that aggregate production and consumption strictly stay within state lines. Counties on state lines do not take into account growth on the other side of the state line or the possibility of importing aggregate from out of state. Future water used for those few counties for which we have reasonable knowledge of production and water use was extrapolated from current use and county population

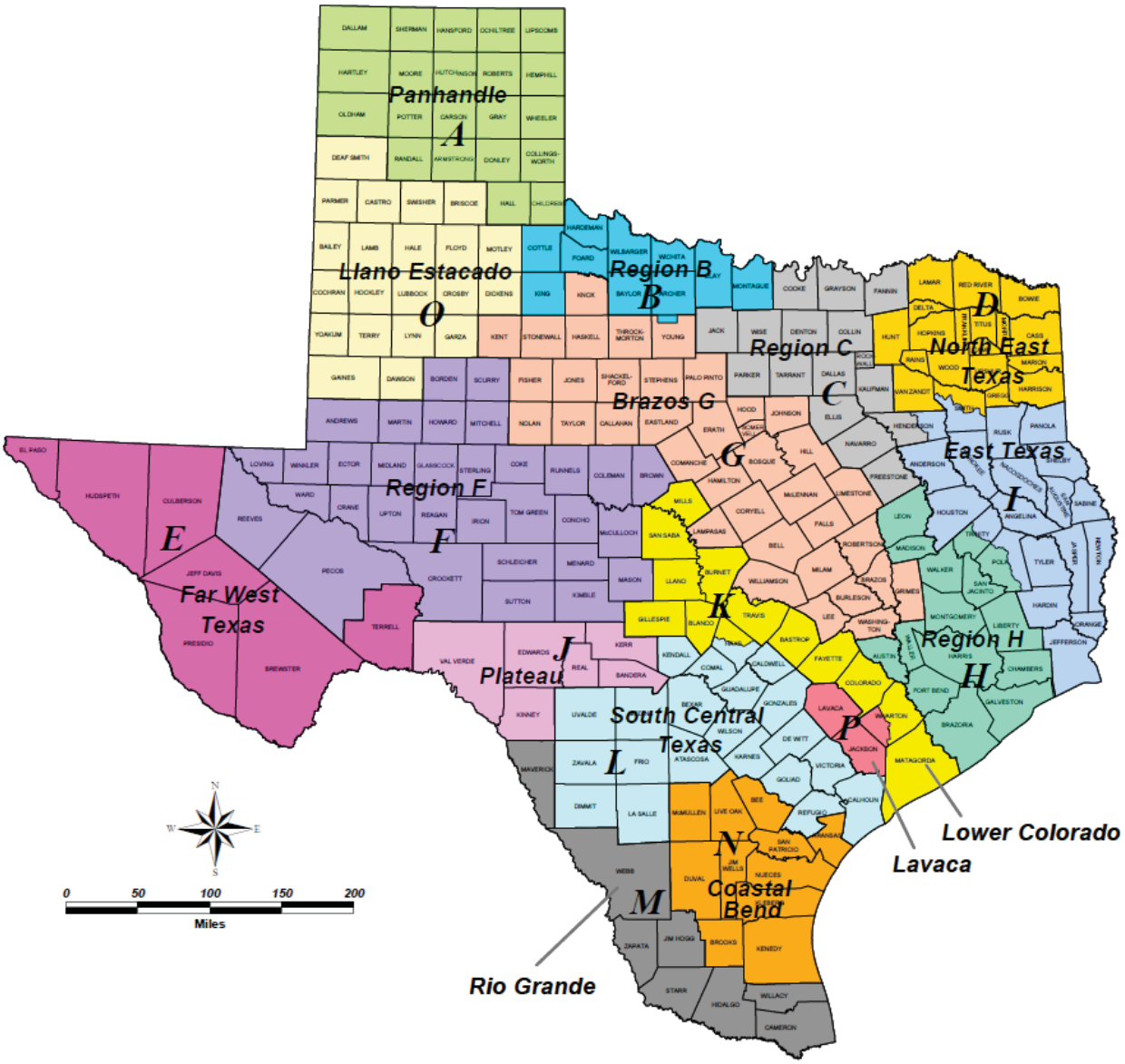
projection according to Eq. 2, with the caveat presented later for urban counties. The remainder of state-level water use was distributed among the remaining counties. Lack of data on individual facilities compelled us to use this approach involving averages that may not necessarily give accurate results at the county level. This lack of data is made worse by the high variability in reported water use. If need be, when new sources of information update average water use, the figures given in this report can simply be scaled by a more accurate value.

Because we based our projections on population growth, aggregate use will also include aggregate recycling (presumably classified in the manufacturing category) and export/import balance from neighboring states. We assumed that both are small and will stay small. Some aggregate recycling has been estimated at 5% of total consumption in 1998 across the nation (USGS, 2000). More recent figures put the amount at 1.7 million tons (USGS, 2010) in Texas (<1%). In addition, we did not assume more water recycling than is currently done. Nor did we include reclamation and irrigation water use in aggregate water use (at least not explicitly).

We also assumed that the same counties will keep operating the same facilities or their extensions, particularly crushed-stone facilities, because of the difficulty to gain acceptance from the public of new large facilities (Robinson and Brown, 2002, p. 3). The main exception concerns urban counties. These authors stated that "*although development and maintenance of infrastructure in metropolitan areas require a continuing supply of aggregate, aggregate production rates begin to fall in counties when the population density reaches approximately 1000 people per square mile. At population densities of about 2000 people per square mile, production of aggregate in many counties may diminish significantly.*" One of the problems of linking population growth and aggregate output at the county level is that counties with high growth are likely to crowd out mining operations and rely on neighboring counties for their aggregate needs. This scenario is assumed true for Travis County in the crushed-stone category and for Bexar, Dallas, Harris, Tarrant, and Travis Counties in the sand and gravel category.

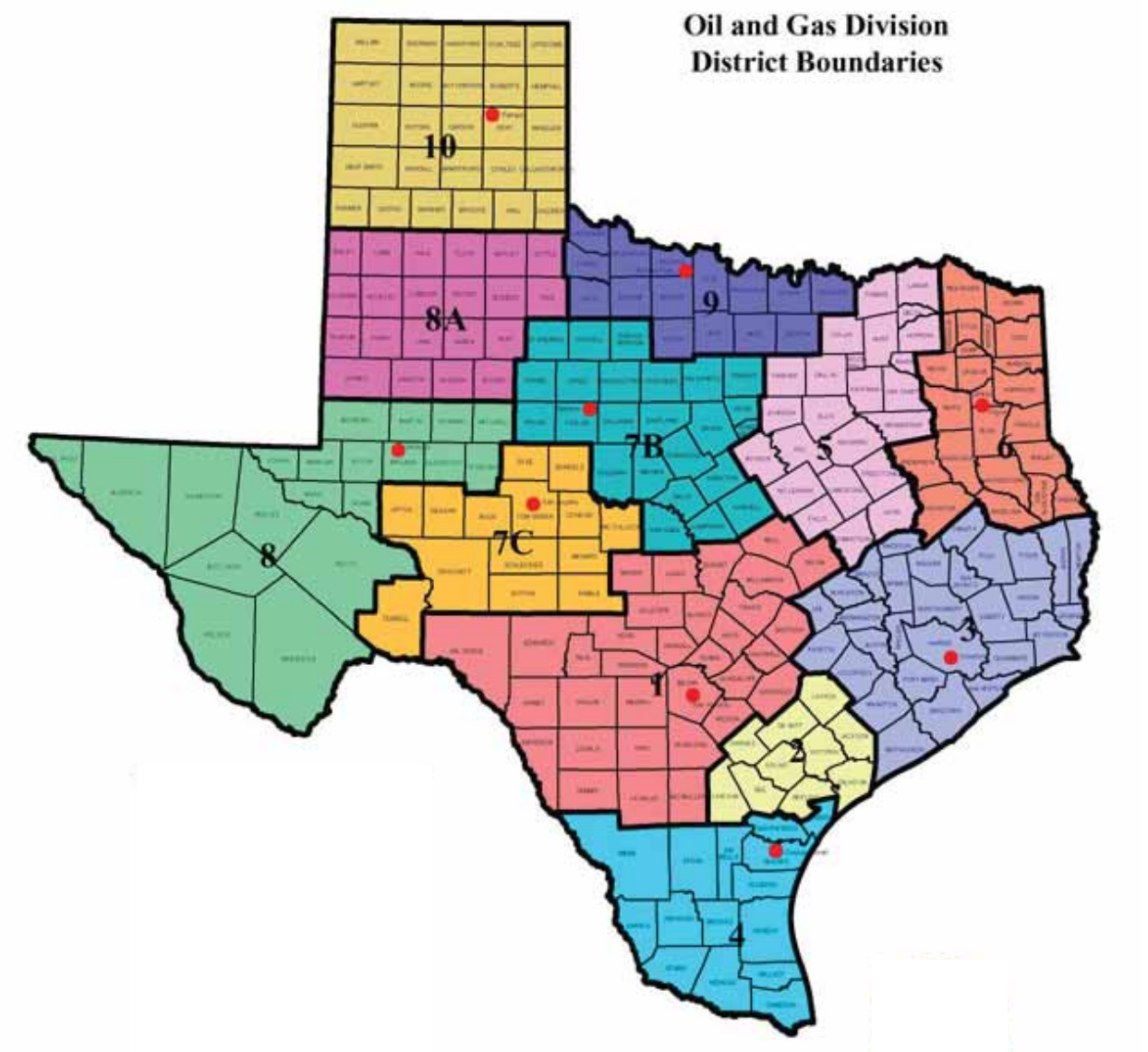
3.4.1.6 Other Mineral Commodities

As was done in the Current Water-Use Methodology Section, future water-use methodology for other mined substances is done on an ad hoc basis. Specific details are given in the Current Water Use section (Section 4.5).



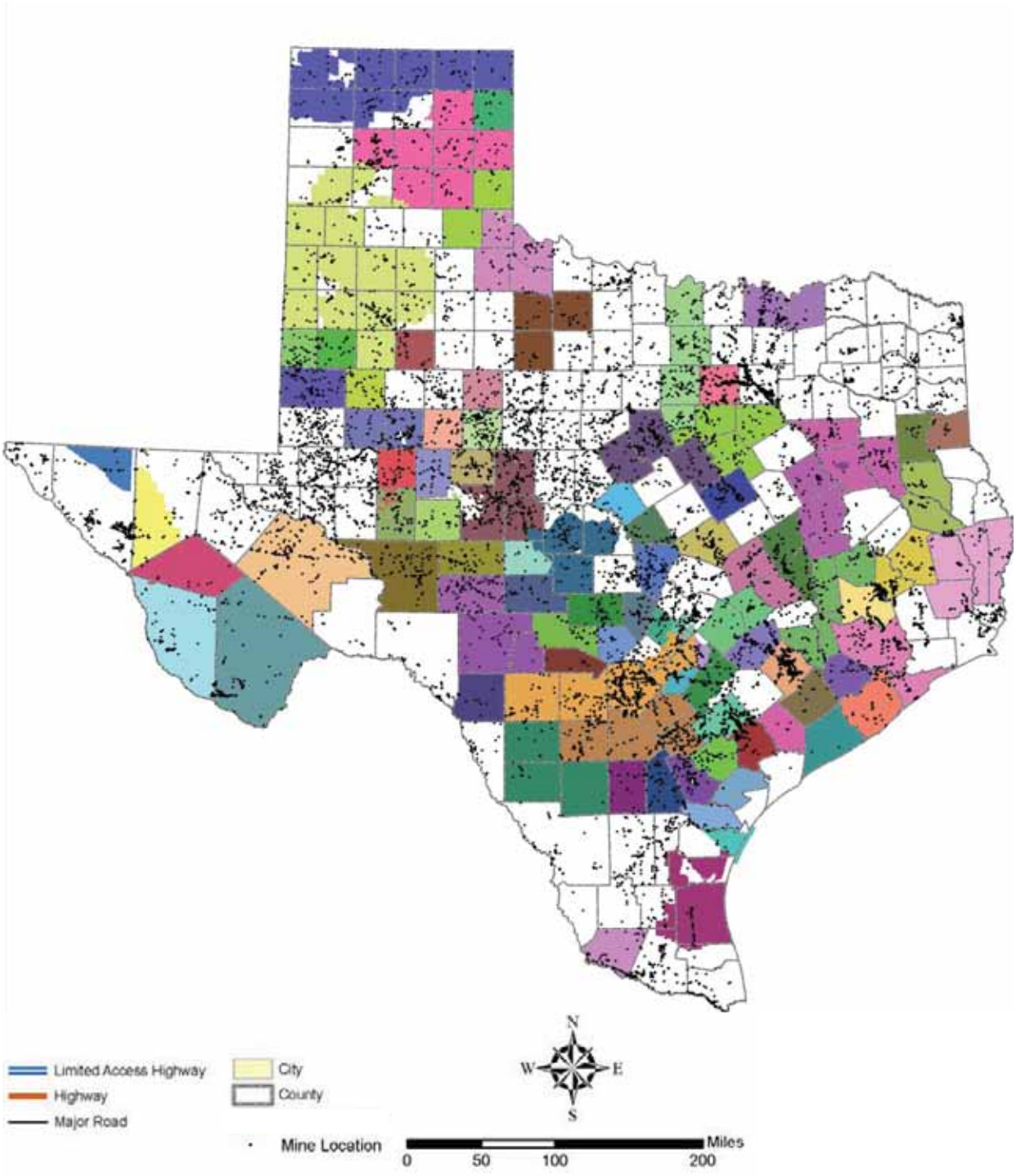
Source: TWDB - http://www.twdb.state.tx.us/mapping/maps/pdf/sb1_groups_8×11.pdf

Figure 8. Map of Regional Water Planning Groups



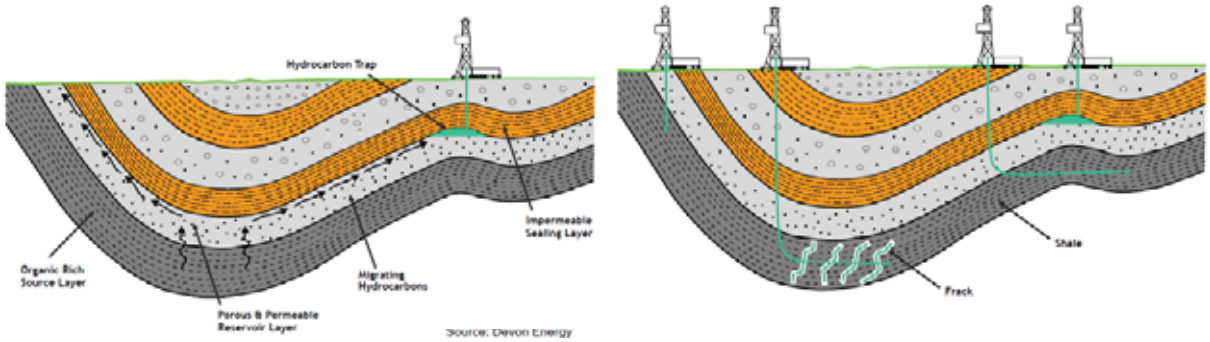
Source: RRC website http://www.rrc.state.tx.us/forms/maps/ogdivisionmap.php

Figure 9. State map of RRC districts



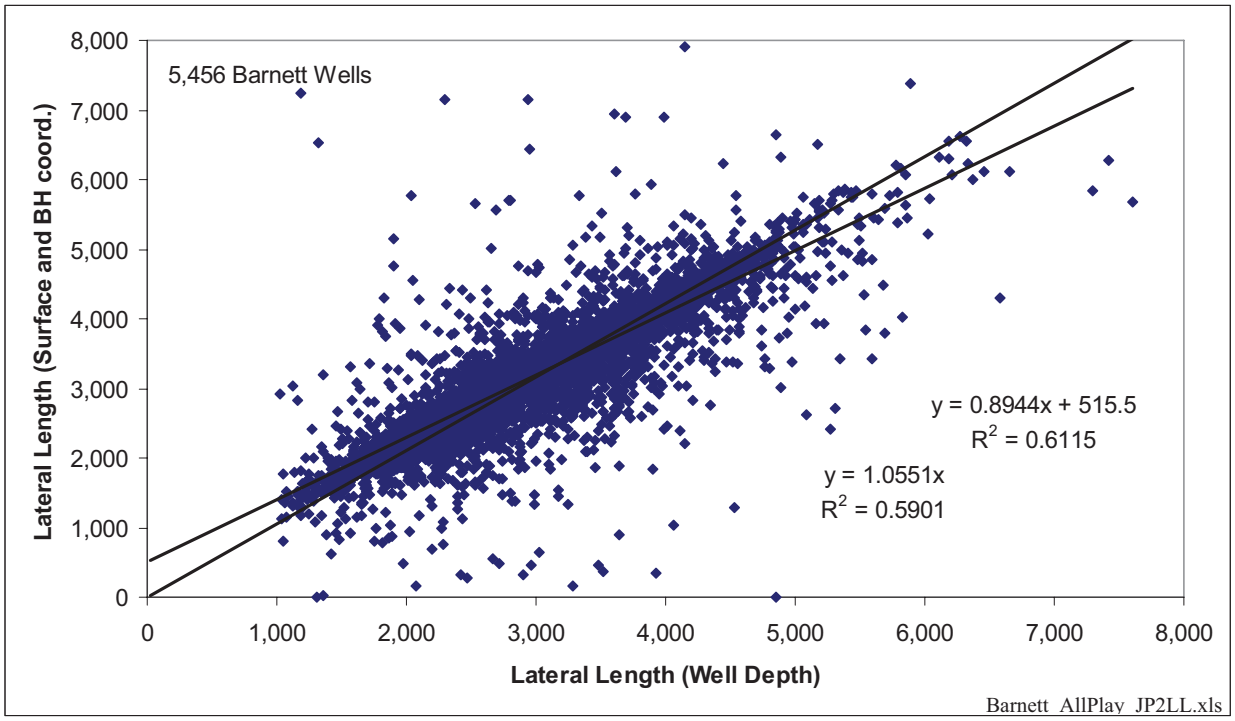
Source: TWDB (GIS coverage of GCDs) and TCEQ SWAP

Figure 10. GCDs and active and inactive mine locations in the TCEQ SWAP database



Source: Devon Energy website

Figure 11. Trap vs. resource play



Note: equation for best fit and fit through the origin are shown. Only those points for which both values are available are shown. Plot also provides estimate of typical and maximum lateral length.

Figure 12. Comparison of the two approaches to compute lateral length

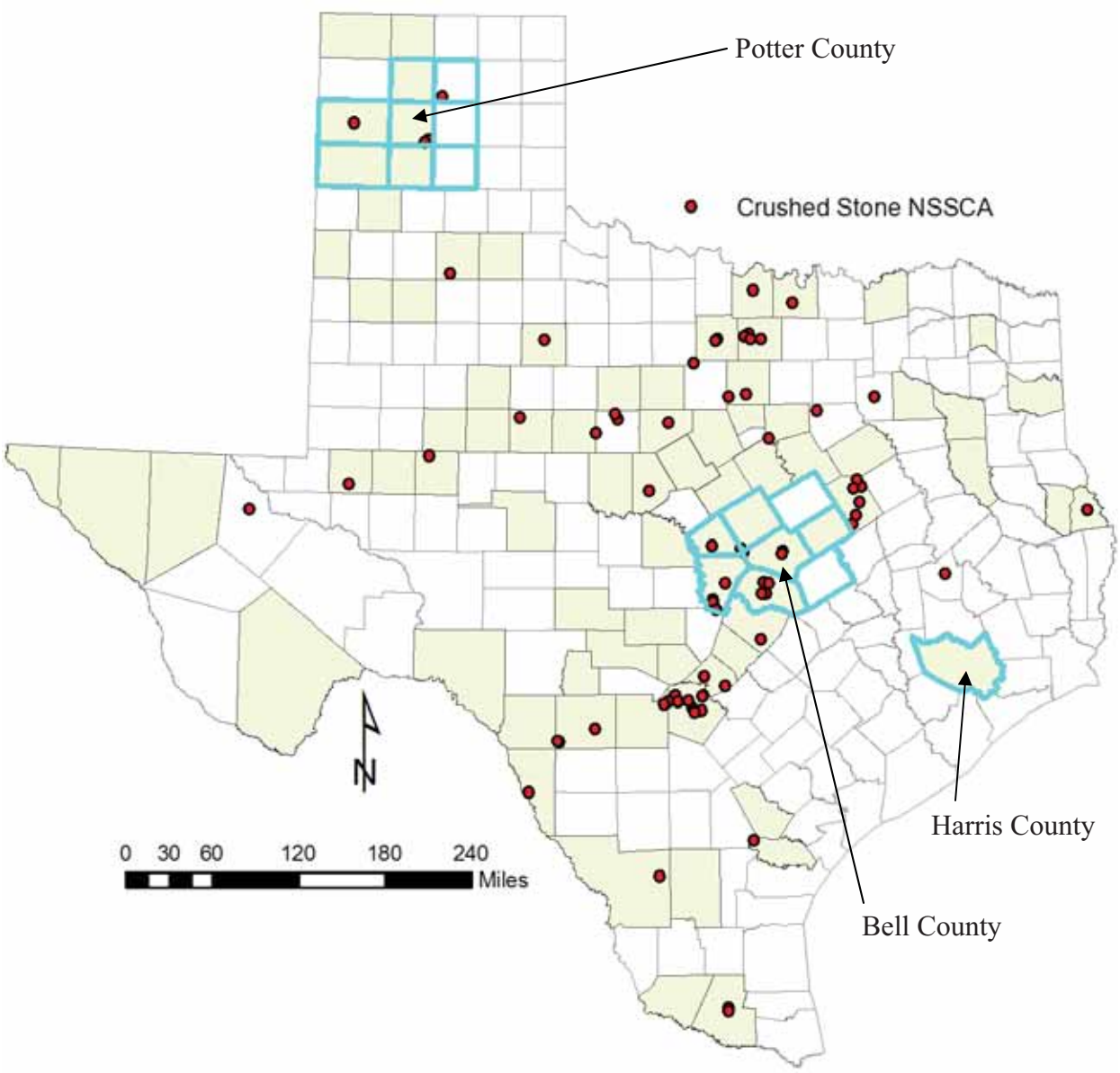
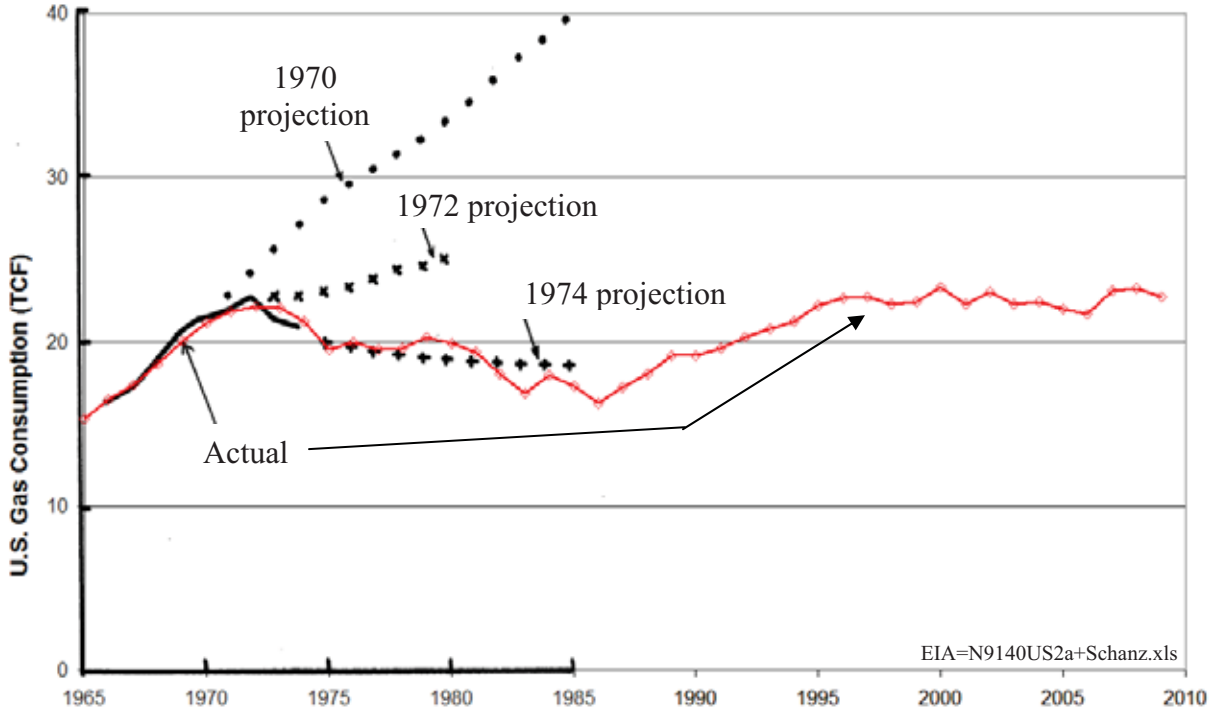
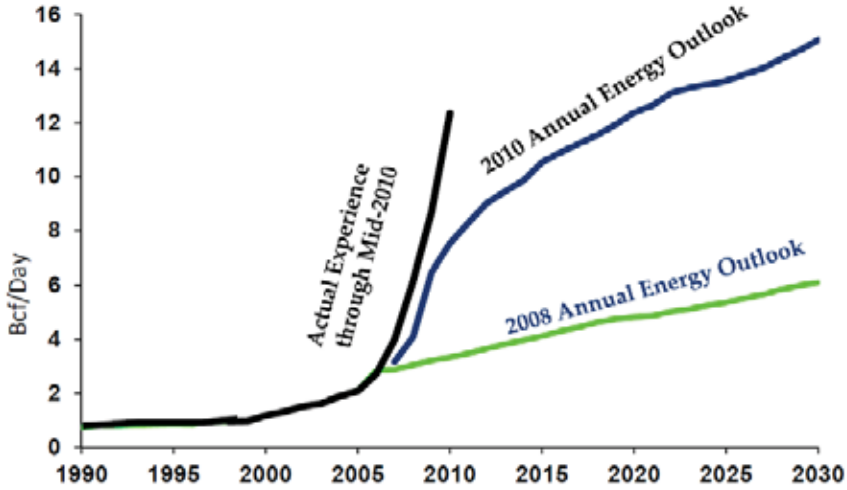


Figure 13. Map illustrating population-count mechanism for crushed-stone facilities. Also showing Potter County and relevant surrounding counties; Bell County and surrounding counties; Harris County count with no NSSGA facility does not include surrounding counties.



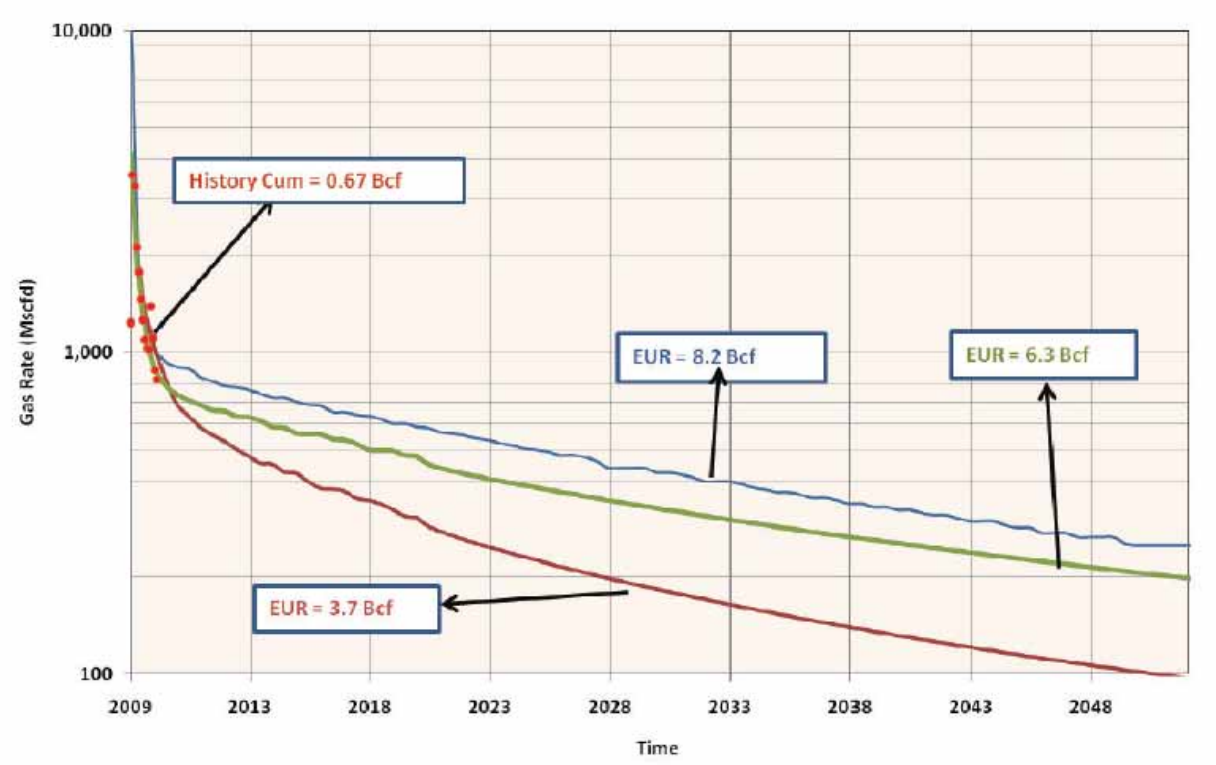
Source: Schanz (1977) and EIA website (gas consumption)
Note: figure superimposes plot from Schanz (1977) showing actual data until 1974 and projections done in 1970, 1972, and 1974 and actual data (red line) until 2009 downloaded from EIA website.

Figure 14. Making long-term projections is an art—part 1



Source: presentation by R. Smead, Navigant
http://www.naseo.org/events/winterfuels/2010/Rick%20Smead%20Presentation.pdf

Figure 15. Making long-term projections is an art— part 2



Source: modified from Vassilellis et al. (2010, Fig. 4)

Figure 16. Multiple EUR projections extrapolated from limited early data for an Eagle Ford well

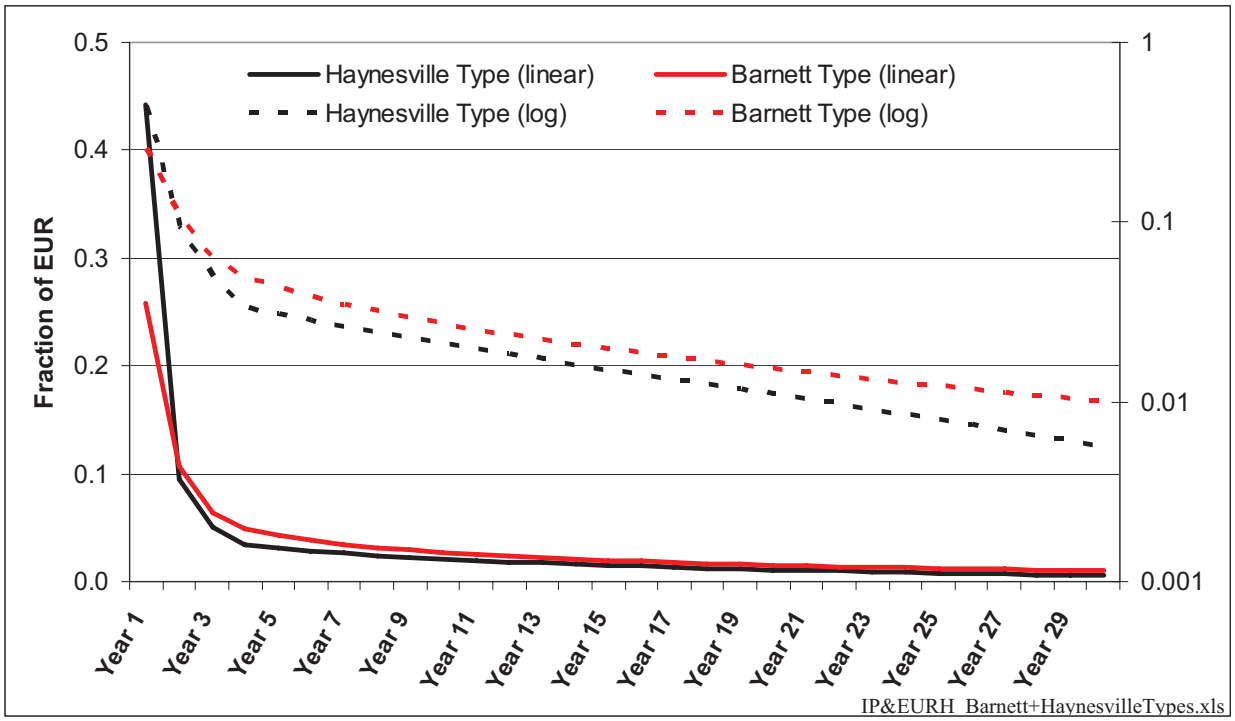
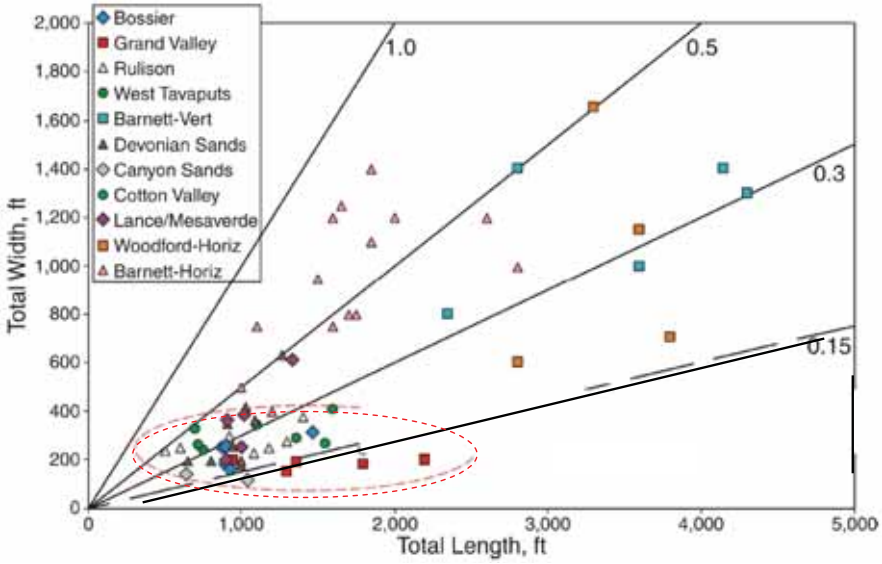
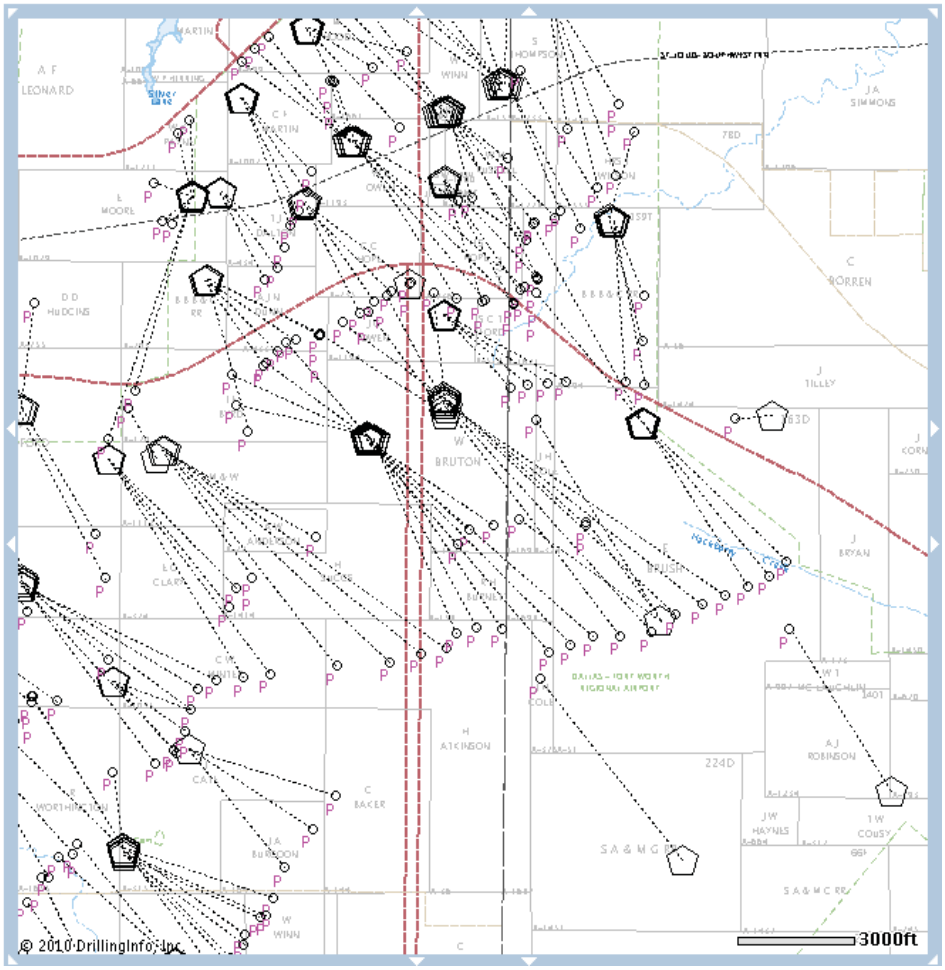


Figure 17. Decline curves assumed in this study (production-based approach)



Source: Chong et al. (2010) modified from Cipolla et al. (2008)

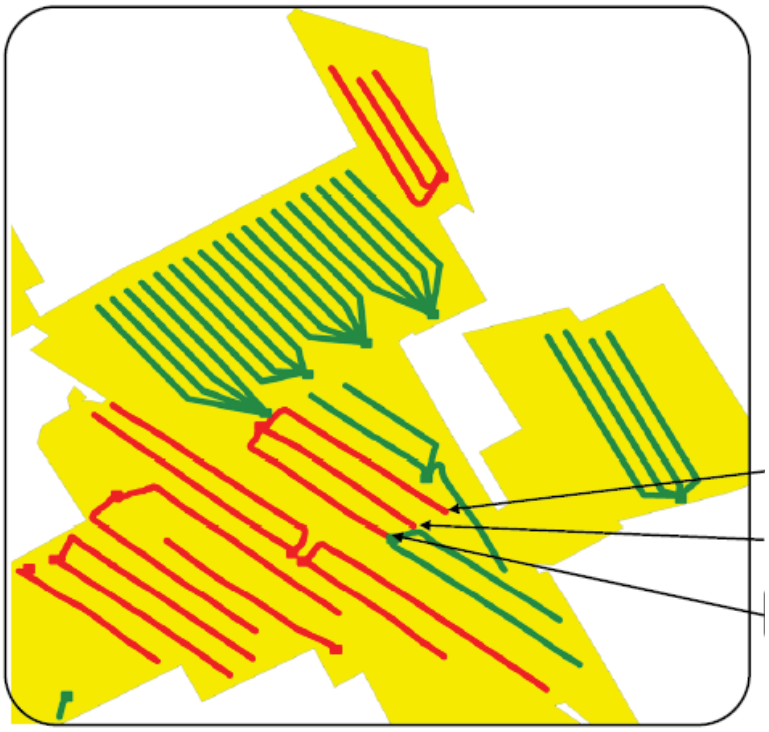
Figure 18. Lateral length vs. estimated impacted width.



Note: map displays an average drainage area of ~80 acres / well (laterals not pads) where laterals are dense.

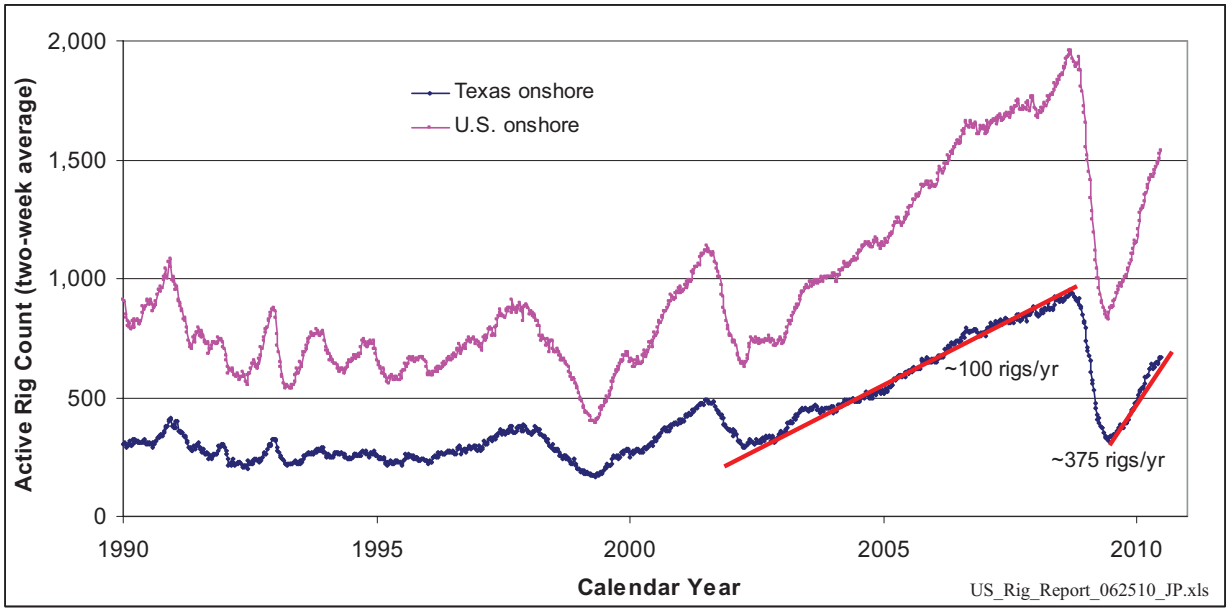
Source Courtesy of DrillingInfo

Figure 19. Example of Barnett Shale density of laterals (Dallas-Tarrant county line)



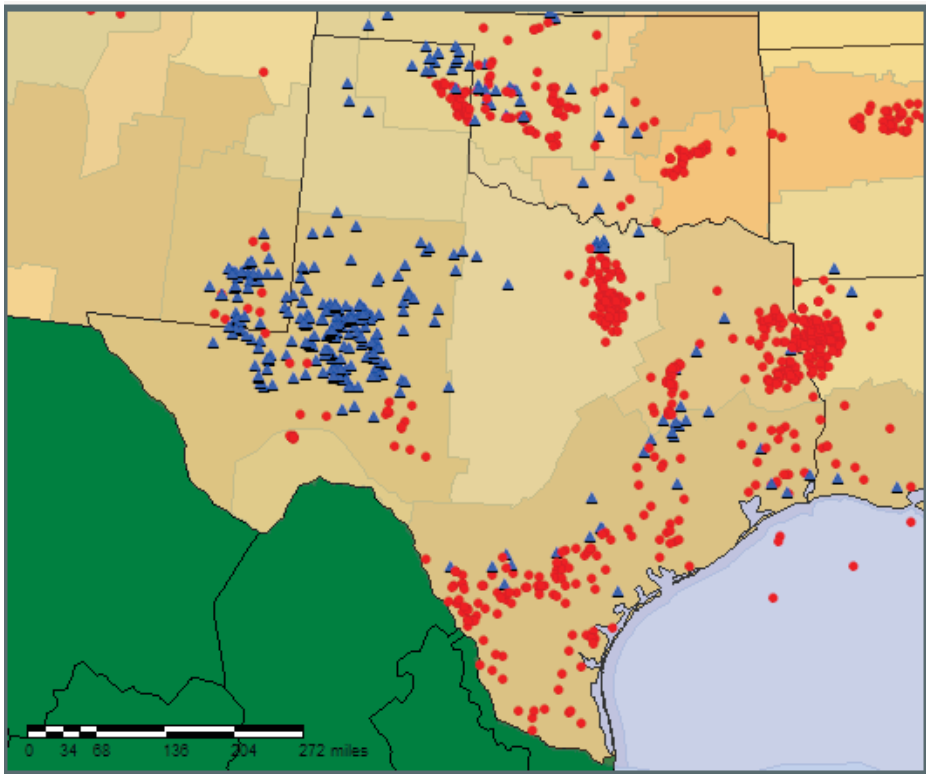
Source: Courtesy EOG Resources— Presentation to analysts, January 2008
Note: 16 completed wells (red trace) and 27 to be completed (planned in 2008)

Figure 20. Example of Barnett Shale density of laterals (Johnson County)

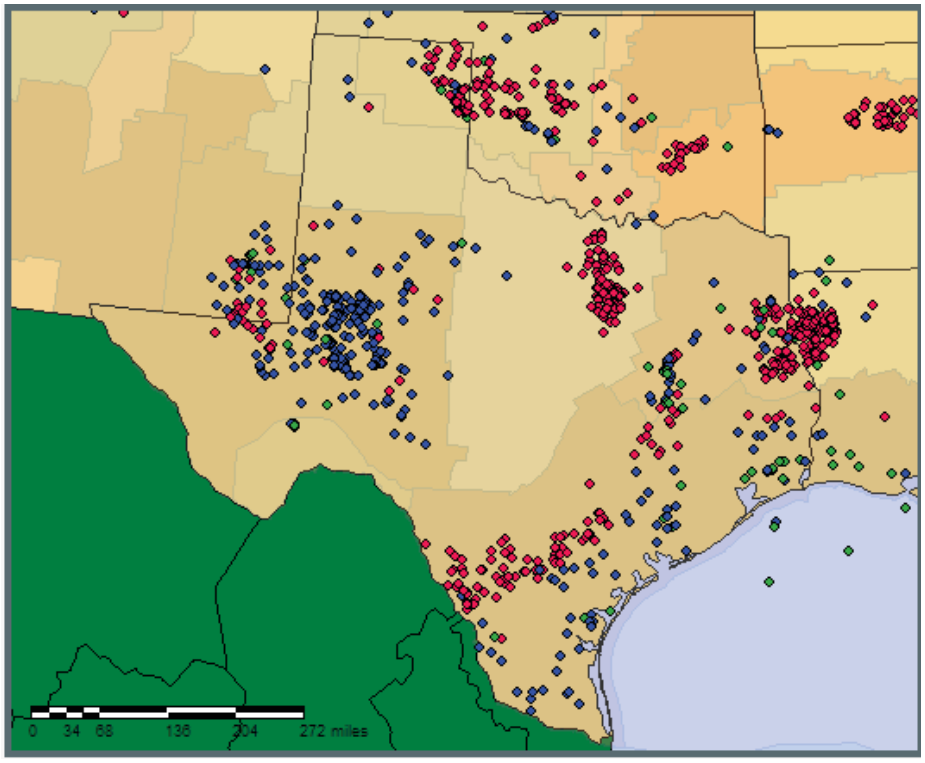


Source: Baker-Hughes website

Figure 21. Active rig count in the U.S. and Texas from 1990 to current



(a)



(b)

Source: Baker-Hughes website

Figure 22. Rig count as of June 25, 2010. (a) Red and blue dots denote gas and oil rigs, respectively; (b) red, blue, and green diamonds denote horizontal, vertical, and directional rigs.

4 Current Water Use

We chose the year 2008 as representative of *current use* for two reasons: (1) this work started in 2009, and not all the 2009 data were yet available, and (2) 2009 is not a representative year because of the economic slowdown; 2008 is the last year with water use more representative of what might occur in the future and is thus more appropriate as a starting point for projections.

4.1 Shales and Tight Sands

The literature on gas shales and related water use is abundant (for example, Arthur et al., 2009; U.S. DOE, 2009) and will not be reprised herein. Several reports also detail current practices in well-pad construction, drilling, completion, and well stimulation for fraced wells. (Veil, 2007; U.S. DOE, 2009; Veil, 2010).

4.1.1 Location and Extent

Section 4.1 provides an overview of the different shale and tight-sand plays in Texas. Present in all corners of the state (Figure 23, Figure 24), they include the Barnett Shale, Haynesville and Bossier Shales, Eagle Ford Shale, Barnett Shale in West Texas, and Woodford Shale, as well as liquid-rich plays such as the Granite Wash in the Anadarko Basin and the Wolfberry in the Permian Basin, the Bossier, Travis Peak and Cotton Valley Tight Sands in East Texas, and multiple formations in South Texas. U.S. DOE published a primer (U.S. DOE, 2009) summarizing the state of knowledge on fracing of gas shales and other tight formations. Good general background can also be found in PGC (2009, p. 179–192). They exist in all major basins of the state (Figure 26).

In terms of approximate numbers, as given by the scoping analysis of the 2005–2009 period, number of frac jobs was >2,500, >4,500, >6,200, >6,600, and >3,700, respectively, from 2005 through 2009, for a total of >23,500 frac jobs (2009 might be incomplete, data downloaded in April 2010). The ">" is used because a nonnegligible fraction of frac jobs is described as such but with no corresponding water-use amount in the IHS database, although it does show proppant use or long laterals, etc. These "zero" water-use wells are assigned water-use amounts as described in the methodology section. In this 5-year period, ~100 formations were fraced (Table 6), but the bulk of the frac jobs are limited to a few formations (Figure 25). In 2005, the Barnett Shale had the larger number of frac jobs (~42%), followed by the Cotton Valley of East Texas (~23%; ~27% if Travis Peak is added), Granite Wash (Anadarko Basin) at ~13%, and Wolfberry in the Permian Basin at 7%. In 2006, the order had not changed: Barnett (~57%), Cotton Valley and some Travis Peak (16%), Granite Wash (~10%), and Wolfberry (~6%). In 2007, the Barnett Shale was still dominant (~62%), but followed by Granite Wash (14%), Cotton Valley and Travis Peak (15%), and then Wolfberry (5%). In 2008, the Barnett Shale still led (~40%), but Wolfberry collected ~15%, followed by Cotton Valley and Travis Peak (~11%) and Granite Wash (~7%). In addition, there is a clear increase in geographic coverage because other plays in the Permian Basin (Grayburg, Canyon, Caballos, Clear Fork), Anadarko Basin (Cleveland), and South Texas (Vicksburg, Olmos) are starting to be fraced. The year 2009 saw an overall decrease in the number of frac jobs, but they are still led by the Barnett Shale (~41%) and Wolfberry (19%). Other previously strong plays, such as Granite Wash (6%) and Cotton Valley (~6%), lose rank as newer fraced plays such as in the Pennsylvanian and Permian of the Permian Basin keep growing in terms of the number of frac jobs. Many plays all around the state go beyond the testing stage as tens of frac jobs are performed on 10+ additional formations. Note

that this ranking is done in terms of number of frac jobs, which may or may not be the same as ranking for water use.

To address the last comment and as a final check on the trends in this fast-evolving field, we performed an analysis of all wells completed in 2010 to date (early November 2010). Among a total of 10,268 completed wells, 7650 (~75%) received a treatment making use of water, including ~3850 wells (~37% of total) using >0.1 Mgal of water (Table 7 and Table 8). The minimum amount of water used is over 6 billion gallons or ~18.5 thousand AF, almost ⅔ of it in the Fort Worth Basin Barnett Shale.

4.1.2 Gas (and Oil) Shales

This report does not comprehensively document the different formations described in this section, but rather focuses on water use and mostly provides information needed to access it and make projections. Water use is different in each play and is impacted by local geological factors. There are three very active "shale gas" (oil is also produced) plays as of end of 2010 in Texas: Barnett, Haynesville/Bossier, and Eagle Ford shales. To them can be added the Pearsall Shale, Barnett and Woodford Shales in the Permian Basin, and perhaps the Bend Shale in the Palo Duro Basin in the Texas Panhandle. A map by EIA (Figure 23a) does display them all but with inaccurate footprints.

4.1.2.1 Barnett Shale

The Barnett Shale (Figure 28) is the formation where the current technology was pioneered, and it has been producing gas since the early 1990s. Productive Barnett Shale is found at depths between 6,500 and 8,500 ft in North-Central Texas, with a net thickness ranging from 100 to 600 ft. Pollastro et al. (2007) and Galusky (2009) provided an update to information presented in Nicot and Potter (2007), whereas Martineau (2007) summarized the history of the play. The Mitchell Energy / C. W. Slay #1, a vertical well, went into production in June 1982, has produced over 1.7 Bcf of gas, and is still producing after 28+ years. It is given credit as the first Barnett Shale producer (PBSN, Nov 1, 2010). As slick-water-frac and horizontal-drilling technologies were being perfected, the balance of wells initially favoring vertical wells is now disproportionally in favor of horizontal wells (Figure 27), with >2500 horizontal wells and only 100+ vertical wells completed in 2008. Figure 29 illustrates the transition and its impact on water use. There is a clear jump in the average water use in 1998 for both horizontal and vertical wells to ~1.5 million gallons/well. The amount of water used then stays more or less constant through time for vertical wells but with a much larger variance, whereas it keeps increasing for horizontal wells until it reaches a current average of 3–4 million gal/well. Progress in the technology is also visible on the histograms of the frac water volume, with a clear bimodal distribution (Figure 30a). The most recent vertical fracs (Figure 30c) display a well-behaved normal distribution centered on ~1.3 million gal/well. A histogram of horizontal well-water use, depicted in Figure 31a, also shows a well-behaved distribution, but with a broad mode and a very large range (from <1 million to >8 million gal/well). However, when reported to the total lateral length (Figure 31b), water intensity seems normally distributed, with a mean/mode of ~1000 gal/ft. Proppant amount distribution is biased toward lower values, with a long tail toward high proppant amount (Figure 32a and Figure 33a). The observation remains true in a plot of proppant loading (Figure 32b and Figure 33b).

Core counties consist of Denton, Johnson, Tarrant, and Wise Counties. Production has been relatively stable in the past 2 years at ~5 million Mcf/d (PBSN, Nov 1, 2010) although the so-

called “combo” play in Montague and Clay Counties in the oil window has seen a recent increase in activity. Other counties (Stephens, Shackelford) south of the core area and in the oil window also seem to stir some interest. Other counties producing from the Barnett are Archer, Bosque, Comanche, Cooke, Coryell , Dallas, Eastland , Ellis, Erath, Hamilton, Hill, Hood, Jack , Palo Pinto, Parker, and Somervell Counties. In 2008, water use in the Barnett Shale was ~25 thousand AF (Table 9). Table 9 also presents completion water use at the county level, with Johnson County displaying the highest water use at ~8.5 thousand AF, followed by Tarrant County at 5.1 thousand AF, and Denton, Wise, and Parker Counties at 2.8, 2.1., and 1.8 thousand AF, respectively.

4.1.2.2 Haynesville and Bossier Shales

The productive interval of the Haynesville Shale of Jurassic age is >10,000 ft deep. It is an organic-rich, argillaceous, silty, calcareous mudstone that was deposited in a restricted, intrashelf basin in relatively shallow water (for example, Spain and Anderson, 2010). The current core area (Texas section) includes Harrison, Panola, Shelby, and San Augustine Counties, but the play also covers Angelina, Gregg, Marion, Nacogdoches, Rusk, and Sabine Counties (Figure 34). Typical thickness of the Haynesville Shale ranges between 300 and 400 ft in western Louisiana and 200 and 300 ft in Texas, at burial depths between 11,000 and 14,000 ft. Further west, the shale transitions to the so-called Haynesville carbonates, which are known for their excellent production from carbonate shoals and pinnacle reefs in the East Texas Salt Basin (Hammes, 2009; Hammes et al., 2009). The Haynesville Shale is overpressured, increasing the amount of gas per unit rock relative to a normally pressured shale.

The first year with significant fracing water use was 2008 (Figure 35), before which date any frac was mostly exploratory in nature. The few vertical wells stimulated in the early years of 2000 (Figure 36) probably targeted carbonate facies. Currently the bulk of wells are horizontal, with a wide range of water use from <1 million to >10 million gal/well (Figure 37a). Water intensity (Figure 37b) is not as clearly defined as it was in the Barnett Shale because of the much smaller sample size, but it stays in the same 1000 to 1200 gal/ft range (we used 1100 gal/ft). Proppant loading is higher on average than that in the Barnett Shale (Figure 38). As of October 2010, the IHS database contained ~100 wells of which ~50 of which have water-use information. After we corrected for obvious typos by assessing water-use intensity (gal/ft) and proppant loading (lb/gal), the total reported water use to date is ~260 million gal. Assigning reasonable water-use values to wells with missing data (through knowledge of proppant amount and/or lateral length), total water use to date (2008 to ~mid-2010) is ~0.5 billion gal or 1.5 thousand AF, 7% of which (0.1 thousand AF) was used in 2008, 50% (0.75 thousand AF) in 2009, and 43% (0.65 thousand AF) during the first ~8 months of 2010.

Groundwater–surface water split is unclear in Texas. However, Louisiana parishes bordering the Texas state line, where gas production started, are also part of the Haynesville core. Initially frac jobs relied heavily on the local groundwater resources of the Carrizo-Wilcox aquifer (Hanson, 2009) but, thanks to a grass-root effort, the bulk of the water use has shifted to surface water (Gary Hanson, LSU Shreveport, personal communication, 2010).

The Bossier Shale directly overlies the Haynesville Shale and represents distal parts of the overlying Cotton Valley siliciclastic wedge. The upper Bossier Shale, dominated by siliciclastics, is not as overpressured, is less organic rich, and contains less TOC than the Haynesville Shale (Hammes, 2009; Hammes and Carr, 2009). The RRC webpage describing the Haynesville combines Haynesville and Bossier, owing to a terminology issue.

4.1.2.3 Eagle Ford Shale

The Eagle Ford Formation of Late Cretaceous age covers a large section of South Texas all the way to East Texas, where it meets the deltaic deposits of the Woodbine Formation of equivalent age, as depicted in the schematic cross section of Figure 39. It lies below the Austin Chalk and is probably the source of its hydrocarbon accumulation. Located at a depth of 4,000–11,000 ft, the play is slightly overpressured (pressure gradient of 0.43 to 0.65 psi/ft; Vassilellis et al., 2010), making it more attractive because of the higher initial production rates. Most current interest is focused on the South Texas section of the Eagle Ford (Figure 40 and Figure 41). The discovery well was drilled by Petrohawk in 2008 in La Salle County (PBSN, Sept 20, 2010). The formation produces natural gas, condensate, and oil. Earlier wells were vertical, located in Central Texas (Brazos, Burleson Counties), and looking for oil. The Central Texas play is somewhat disconnected from the South Texas play (from the Mexican border to Gonzales and DeWitt Counties) by the San Marcos Arch, a constant higher-elevation structural feature (Figure 39). The Eagle Ford Shale contains oil updip, gas downdip, and gas and condensates in between. The "shale" is carbonate rich, up to 70% calcite (Cusack et al., 2010, p. 171), much higher than that of the Barnett Shale, which makes it more prone to fracing. The play is still too young to determine the location of the core area, if it exists, but most of the fracing has taken place in Dimmit, LaSalle, and Webb Counties.

As of October 2010, the IHS database contained ~270 wells, 174 of which have water-use information (Figure 42), almost all of them horizontal (Figure 43). The average frac water amount is higher than either the Barnett or Haynesville (Figure 44a), ranging from ~1 to >13 million gal/well. A histogram of water intensity shows that this shale is not as well behaved as the two previous shales (Figure 44b). We used an average of 1250 gal/ft. Total proppant amount being correlated to total water use is higher than in the Barnett and Haynesville (Figure 45a), but the proppant loading lies in between (Figure 45b). After correcting for obvious typos by assessing water-use intensity (gal/ft) and proppant loading (lb/gal), we found the total reported water use to date to be ~977 million gal. Assigning reasonable water-use values to wells with missing data (through knowledge of proppant amount and/or lateral length), we found total water use to date (~mid-2008 to ~mid-2010) to be 1.43 billion gal, or 4.4 thousand AF, 3% of which was used in 2008 (0.13 thousand AF), 37% (1.6 thousand AF) in 2009, and 60% (2.6 thousand AF) during the first ~8 months of 2010.

4.1.2.4 Woodford, Pearsall, Bend, and Barnett-PB Shales

The extent of the Woodford Formation of Devonian age is shown in Figure 46. It covers most of the Permian Basin and a small area of what would become the Central Basin Platform. It can be as thick as 600 ft in Loving and Winkler Counties but radially decreases to <100 ft outward to subcrop boundaries. In the Delaware Basin depth can reach 15,000 ft, whereas shale is ~7,000 to 9,000 ft deep in the Midland Basin. The main current target in the Anadarko Basin in Oklahoma is also shown, where the formation is called the Caney Shale. The Woodford Shale is stratigraphically equivalent to several Devonian black shales in North America, including the Antrim Shale in the Michigan Basin and the Bakken Formation in the Williston Basin (Comer, 1991, p. 6). Overall, maturity of the Woodford in the Permian Basin seems low and unpromising.

The Permian Basin Barnett seems more clay rich and not as organic rich as in the Fort Worth Basin. Figure 47 displays occurrences of the Barnett Shale in the Permian Basin. Its well-known occurrence in the Fort Worth Basin is also displayed. Kinley et al. (2008) provided a description of its most promising occurrences in the Delaware Basin. Thickness of Mississippian-age

sediments in the Permian Basin is larger and can be >2000 ft in what would become the Delaware Basin and has a maximum of 700 ft in the Midland Basin.

The Pearsall Shale (Loucks, 2002; Hackley et al., 2009a) is overpressured (Wang and Gale, 2009, p.785–786; Vassilellis et al., 2010) with a pressure gradient of 0.80 to 0.89 psi/ft and is located at depths between 7,000 and 12,000 ft. Water use has been small, given the limited number of wells drilled so far.

Figure 48 displays the surge in drilling starting in 2006 and subsiding in 2009 in those 3 West Texas plays (13 in the Woodford, 12 in the Pearsall, and 22 in the Barnett-PB), with a mix of vertical and horizontal wells (Figure 49). Overall frac water use per well remains small (Figure 50) at <2 million gal per well, probably because the plays have not seen much activity in the past 2 years. Woodford, Pearsall, and Barnett-PB shales total 11.3, 44.2, and 37.8 million gal, respectively, that is, 0.035, 0.14, and 0.12 thousand AF, respectively.

The Bend Shale in the Palo Duro Basin does not seem to live up to earlier expectations, although older BEG and other reports (Dutton, 1980; Dutton et al., 1982; Brister et al., 2002; Jarvie, 2009) have credited the basin with some oil and gas generation potential. There is a scarcity of information on this shale that was described early on as a good prospect. The Palo Duro's Bend Shale tests as thermally mature and reaches gross thicknesses between 500 and 1,000 ft at depths from 7,000 to 10,500 feet (Wagman, 2006). No further work is done in this study on the Bend Shale in the Palo Duro Basin.

4.1.2.5 Conclusions on Gas Shales

Completion water-use shale-gas wells was dominated (99.0%) by the Barnett Shale in 2008 at ~25.5 thousand AF used (Figure 51 and Figure 52), whereas, as detailed in the next section, all tight formations across the state amount to ~10.4 thousand AF (Table 10). In 2008, Johnson County in the Barnett Shale footprint achieved the highest water use at 8.5 thousand AF. Note that this water-use amount includes some recycling, but, as will be described in the Future Water Use section, it is likely to be at the very most 10% and more likely just a few percent. Also note that some of the water used directly originates from stormwater collection systems and is thus not considered surface water or groundwater. However, the fraction of this source among the total water used cannot be determined easily because undoubtedly many surface ponds are filled with landowner-supplied groundwater.

Table 6. List of formations currently being fraced heavily or with the potential of being fraced heavily in the future

Name	Basin/Subbasin	IHS Word Search
Gas Shales:		
Barnett	Fort Worth	Barnett, Ellenburger, Forestburg, Marble Falls, Viola
Barnett PB	Permian	Barnett
Haynesville	East Texas	Haynesville
Eagleford	GC Rio Grande	Eagleford
Pearsall	Maverick	Pearsall
Woodford-PB	Permian	Woodford
Woodford-AB	Anadarko	Woodford
Tight Gas		
Anadarko Basin		
Atoka-AB	Anadarko	Atoka, Bend, Morrow, Granite Wash, Pennsylvanian
Cleveland	Anadarko	Cleveland, Marmaton, Cherokee, Kansas, Caldwell
East Texas Basin		
James	East Texas	James
Pettet	East Texas	Pettet, Pettit, Sligo
Travis Peak	East Texas	Travis Peak, Hosston
Cotton Valley	East Texas	Cotton Valley, Austin Chalk, Taylor, Gilmer, Schuler, Buckner
Bossier	East Texas	Bossier
Smackover	East Texas	Smackover
Fort Worth Basin		
Atoka-FWB	Fort Worth	Atoka, Bend, Morrow, Granite Wash, Pennsylvanian
Permian Basin		
San Andres	Midland+CBP	San Andres, Grayburg (Glorieta, Abo, Wichita)
Spraberry	Midland	Spraberry, Dean
Clear Fork	CBP	Clear Fork
Bone Spring	Delaware	Bone Spring
Wolfcamp	Midland	Wolfcamp
Cisco	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Canyon	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Strawn	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Atoka-PB	Permian	Atoka, Bend, Morrow, Granite Wash
Devonian	Permian	Devonian, Thirtyone, Devonian Cherts, “Silurian”
Canyon Sands	Val Verde	Canyon, Canyon Sands
Caballos	Marathon	Caballos, Tesnus
Gulf Coast Basin		
Vicksburg	Gulf Coast	Vicksburg, Frio, Hackberry
Wilcox	Gulf Coast	Wilcox, Indio, Tucker, Lobo, Sabine Town
Olmos	Gulf Coast	Olmos, San Miguel, Navarro, Escondido

Table 7. Well statistics and water use for 2010

Category	Water Use (% of Total)	Number of Wells (% of Total)	Vertical Wells (% of Wells for Category)
Not fraced	0.0%	25.6%	
Stimulated	1.7%	34.6%	
Anadarko Basin	3.0%	2.2%	28.1%
East Texas Basin	7.8%	5.0%	44.8%
Fort Worth Basin	57.3%	13.6%	2.0%
Gulf Coast	12.3%	4.8%	33.4%
Permian Basin	17.9%	14.1%	94.1%

Table 8. Major active formations in 2010 completed well count

Category	Play/Formation	Count
Anadarko Basin	Granite Wash and others	124
	Cleveland	50
	Marmaton	18
	Others	18
	Total	**210**
Permian Basin	Delaware Group	32
	Spraberry/Dean/Wolfcamp	863
	Clear Fork	232
	Canyon Sands	48
	Caballos/Tesnus	19
	Others	168
	Total	**1362**
East Texas Basin	Cotton Valley Group	200
	Travis Peak	47
	Haynesville/Bossier Shales	115
	Cotton Valley Sands	26
	Others	99
	Total	**487**
Gulf Coast Basin	Eagle Ford	193
	Olmos	68
	Vicksburg	39
	Wilcox/Lobo	64
	Frio	20
	Others	80
	Total	**464**
Fort Worth Basin	Barnett Shale	1295
	Others	23
	Total	**1318**
Stimulated only (<0.1 Mgal)	Permian Basin	2460
	East Texas	315
	Gulf Coast	169
	Fort Worth	132
	Others	733
	Total	**3809**
Not Stimulated	Frio	482
	Wilcox	185
	Austin Chalk	140
	Others	1811**
	Total	**2712**

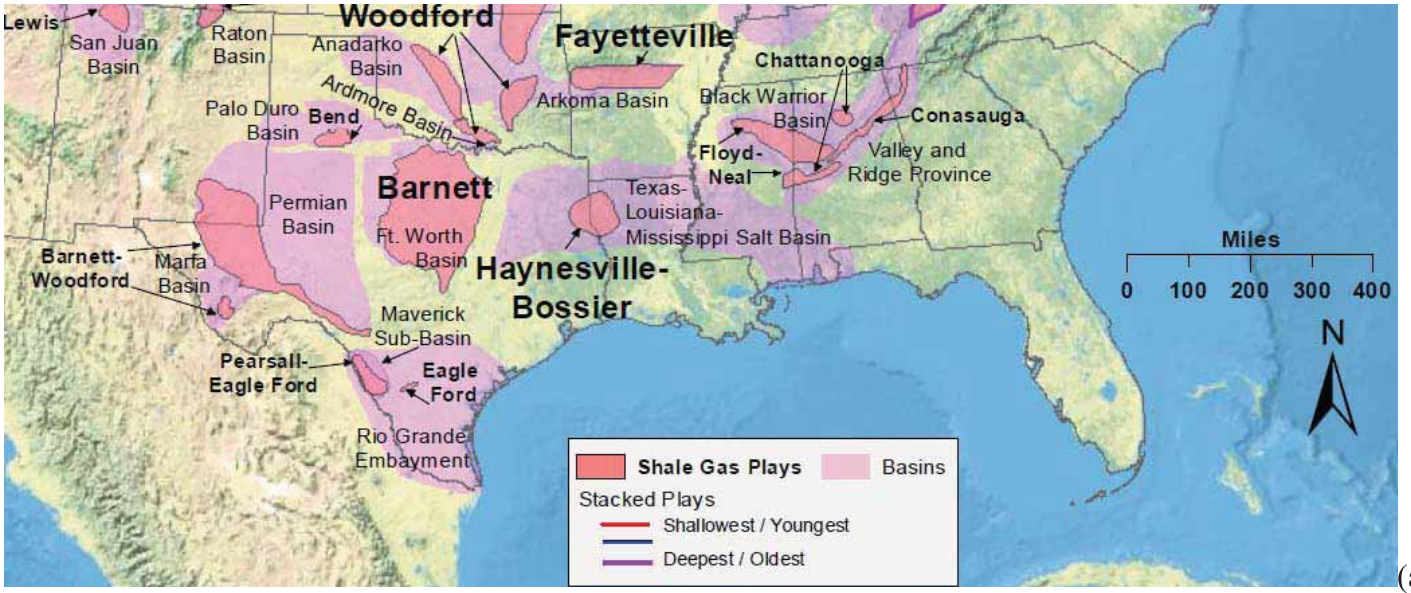
Table 9. County-level shale-gas-completion water use in the Barnett Shale (2008)

County	Water Use (thousand AF)	County	Water Use (thousand AF)
Archer	0.003	Jack	0.085
Brazos	0.008	Johnson	8.459
Burleson	0.034	La Salle	0.010
Clay	0.020	Maverick	0.007
Cooke	0.229	Montague	0.571
Culberson	0.045	Palo Pinto	0.206
Dallas	0.076	Panola	0.036
Denton	2.752	Parker	1.768
Dimmit	0.044	Reeves	0.048
Eastland	0.012	Rusk	0.011
Ellis	0.096	Somervell	0.171
Erath	0.295	Tarrant	5.147
Harrison	0.058	Webb	0.007
Hill	1.137	Wise	2.217
Hood	2.154	**Total**	**25.70**

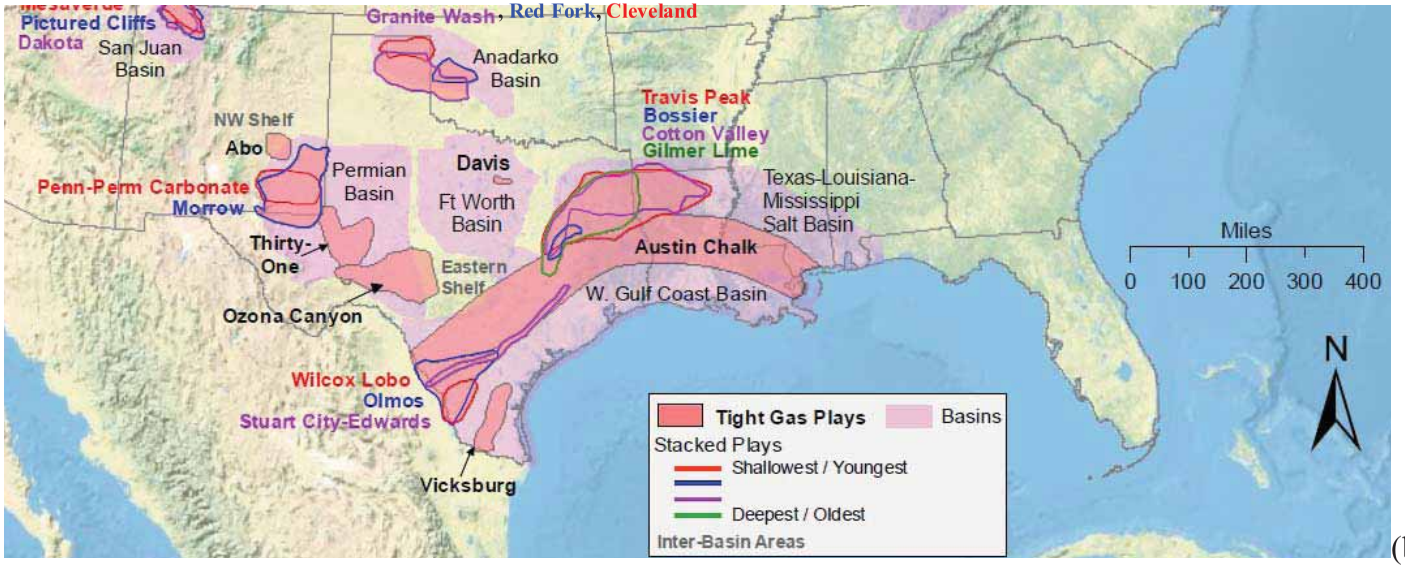
Table 10. Summary of fracing water use

Play	Water Use (thousand AF)
Barnett Shale	25.45
Haynesville Shale	0.11
Eagle Ford Shale	0.07
Woodford/Barnett PB/Pearsall Shale	0.09
Anadarko Tight Formation	2.22
East Texas Tight Formation	4.26
Permian Basin Tight Formation	3.09
Gulf Coast Tight Formation	0.6
Caballos/Tesnus Tight Formation	0.17
Sum Shale (filtered at >0.001 Mgal)	25.71
Sum Tight Fm. (filtered at >0.001 Mgal)	10.33
Sum All (filtered at >0.001 Mgal)	36.04

MiningWaterUse2008_2.xls



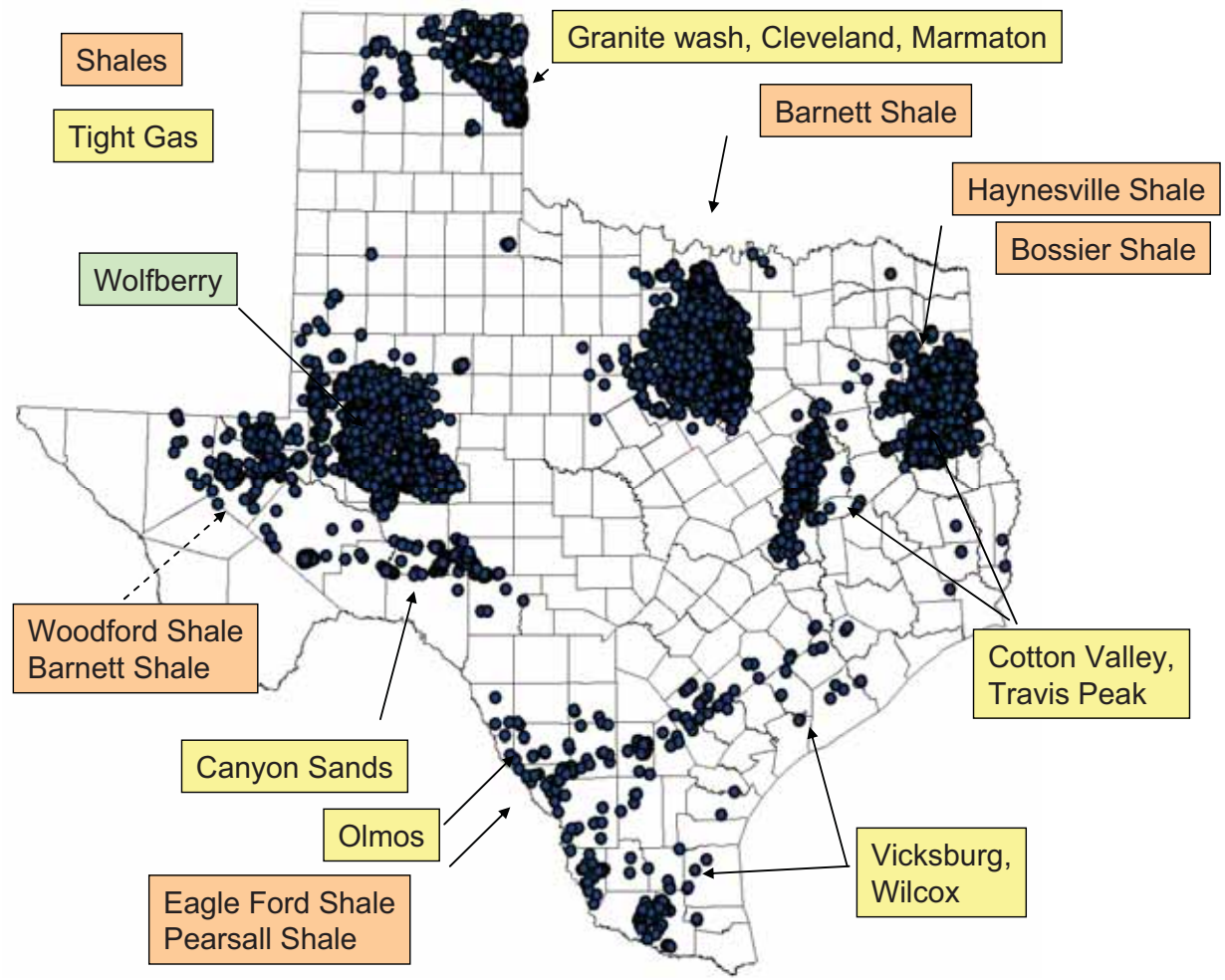
(a)



(b)

Source: EIA website, updated Spring 2010

Figure 23. EIA spatial definition of shale-gas and tight-gas plays



Source: IHS database

Figure 24. Map showing locations of all frac jobs 2005–2009, and main (mostly) gas plays

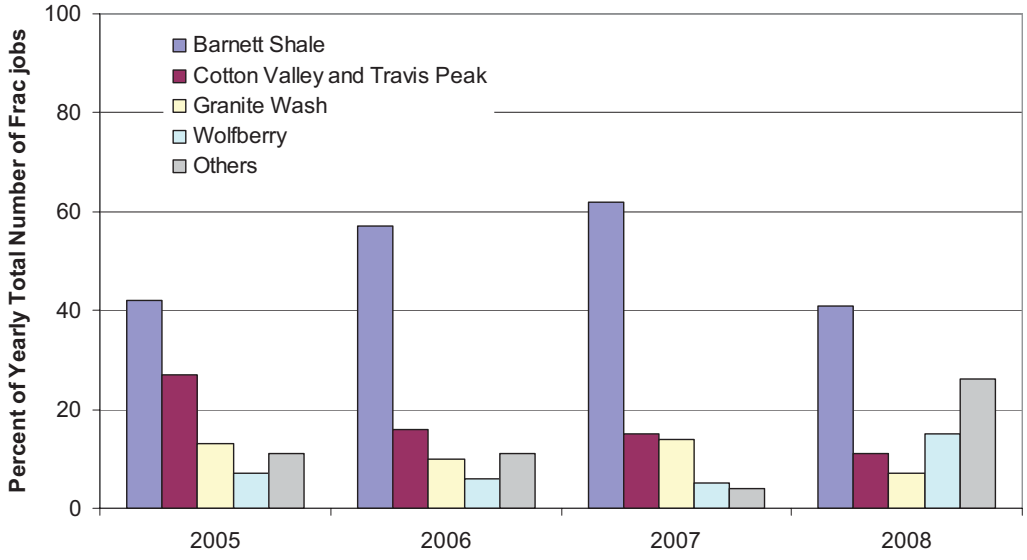
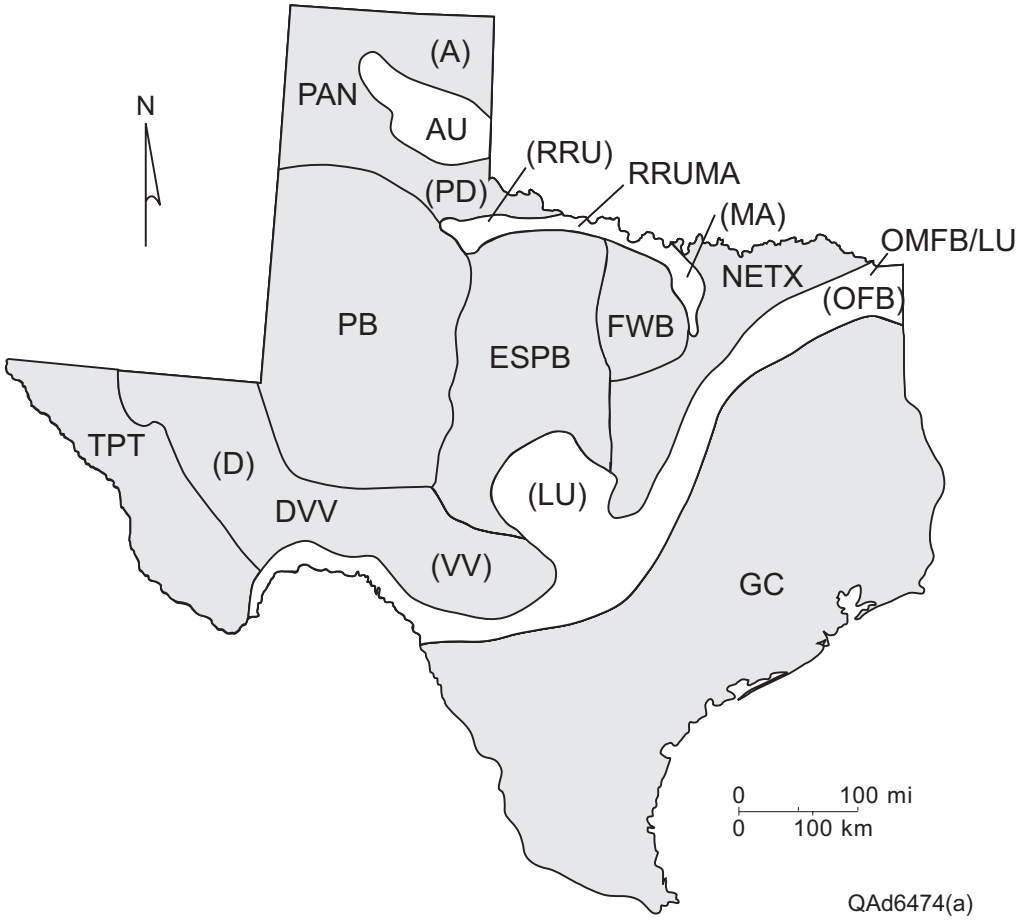


Figure 25. Percentage of frac jobs (not water use) in major plays in 2005-2008



Source: Ambrose et al. (2010)
Note: Regions are: AU Amarillo Uplift, DVV Delaware (D) and Val Verde (VV) Basins, ESPB Eastern Shelf of the Permian Basin, FWB Fort Worth Basin, GC Gulf Coast, LU Llano Uplift, NETX Northeast Texas, OFB Ouachita Foldbelt, OMFB/LU Ouachita and Marathon Foldbelts and Llano Uplift, PAN Texas Panhandle, PB Permian Basin, PD Palo Duro Basin, RRUMA Red River Uplift (RRU)-Muenster Arch (MA), TPT Trans-Pecos Texas

Figure 26. Major geologic regions (basins and uplifts) in Texas

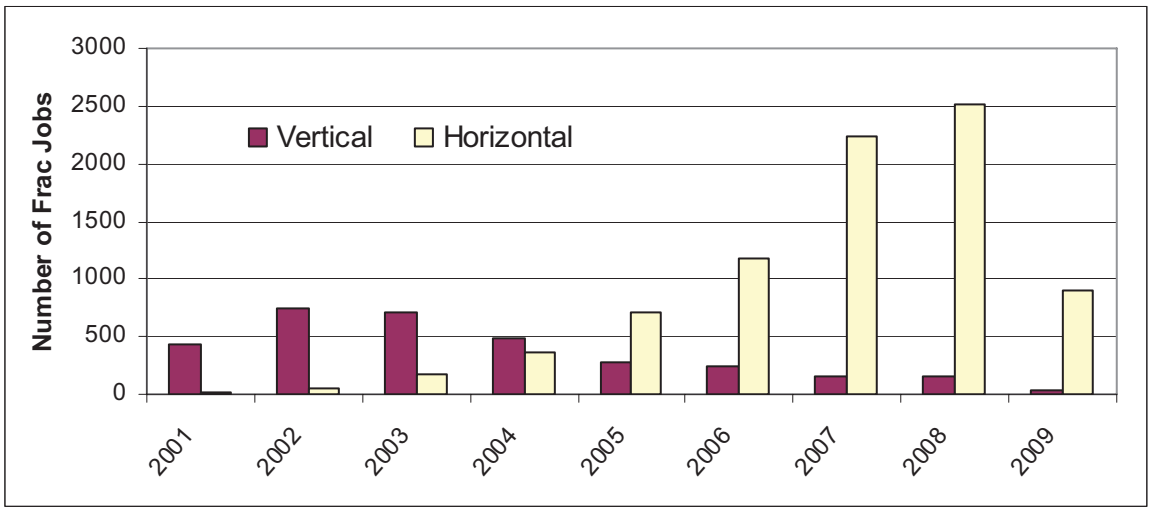
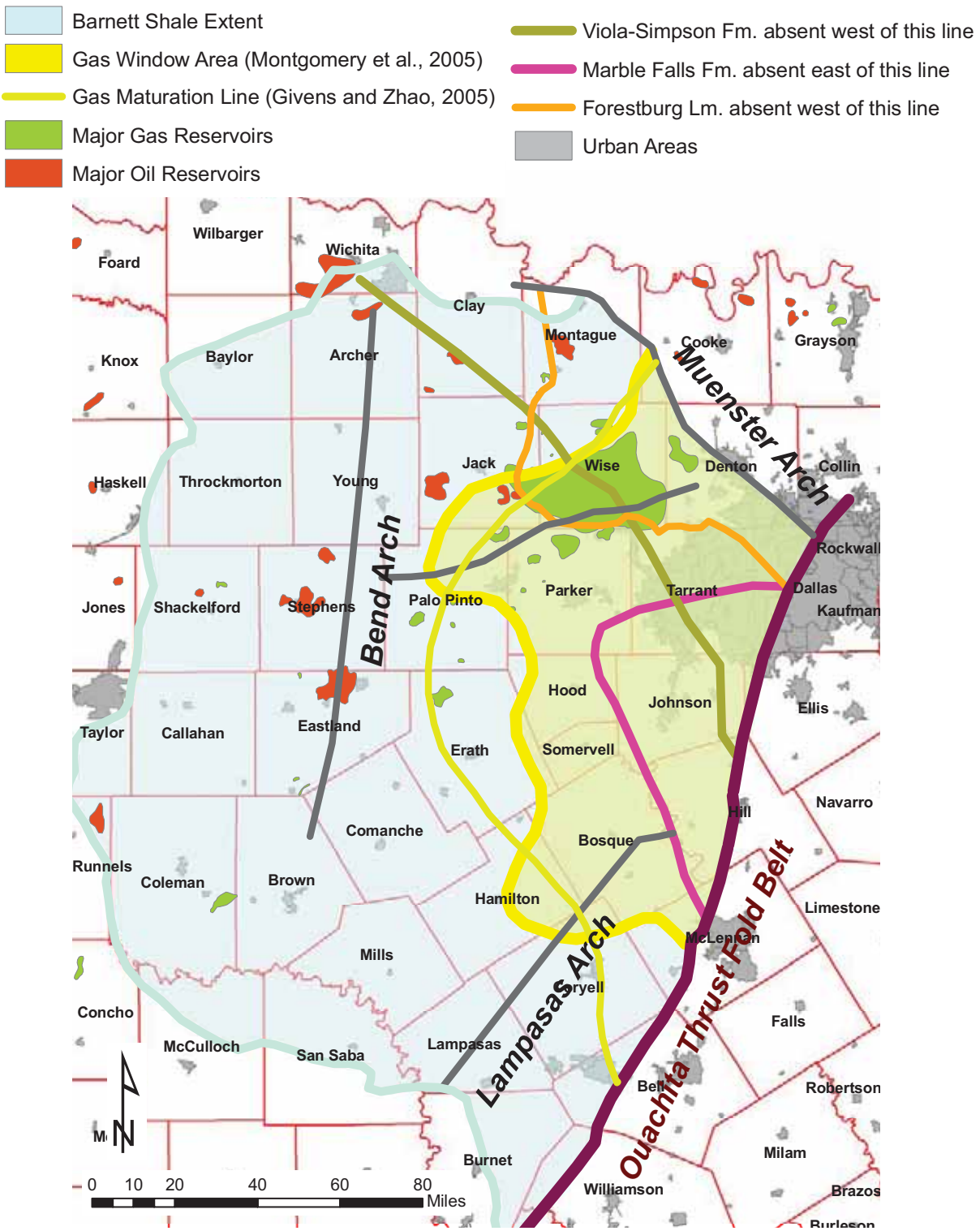
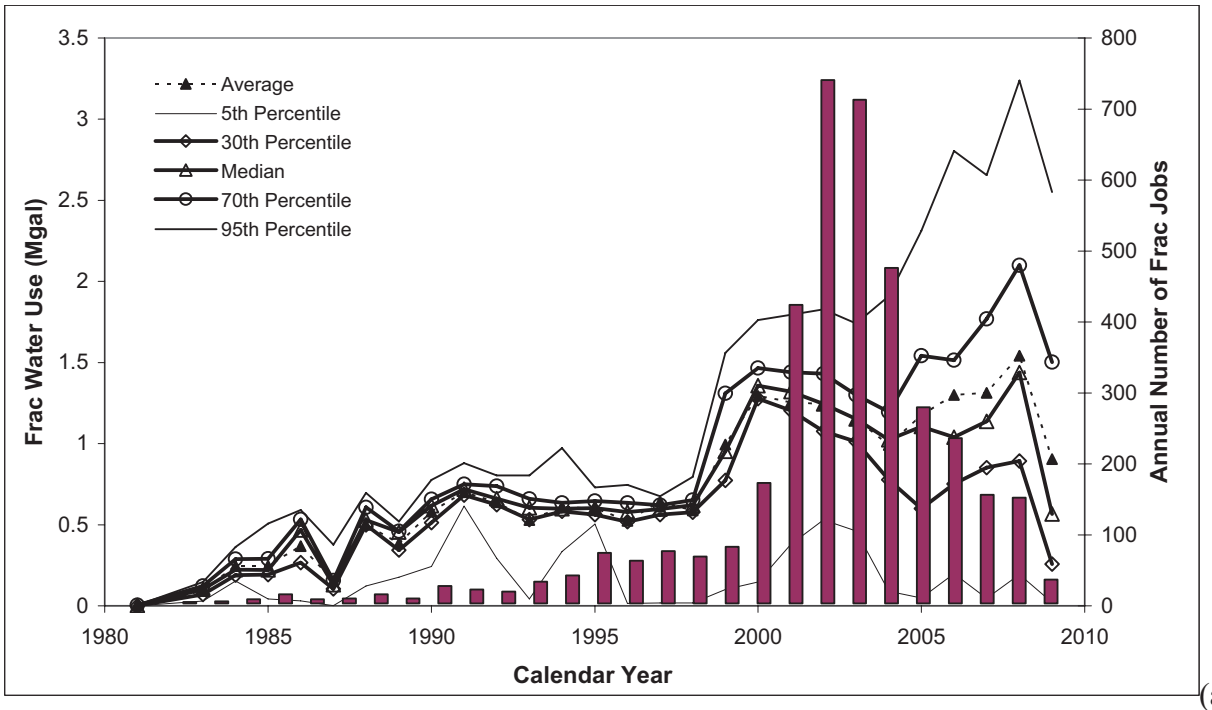


Figure 27. Barnett Shale—vertical vs. horizontal and directional wells through time

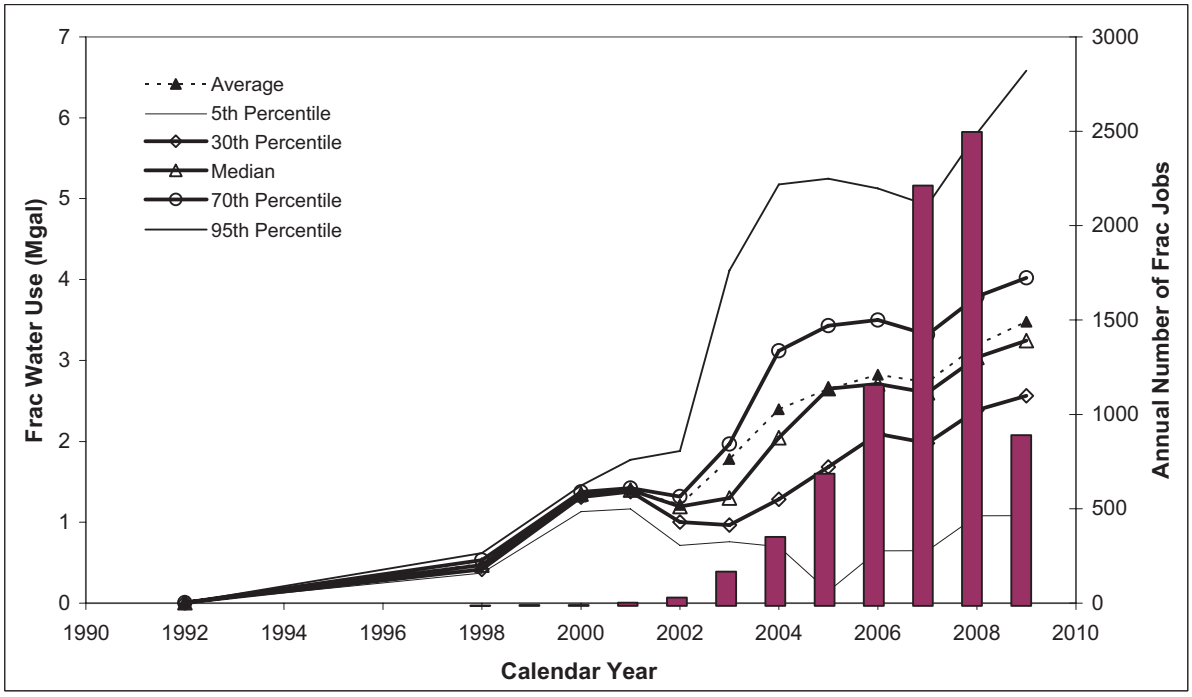


Source: Nicot and Potter (2007)
Note: Forestburg limit modified from Zhao et al. (2007); all others modified from Montgomery et al. (2005); major oil and gas reservoirs from Galloway et al. (1983) and Kosters et al. (1989). The Major Gas and Oil Reservoirs refer to non-Barnett production.

Figure 28. Barnett Shale footprint

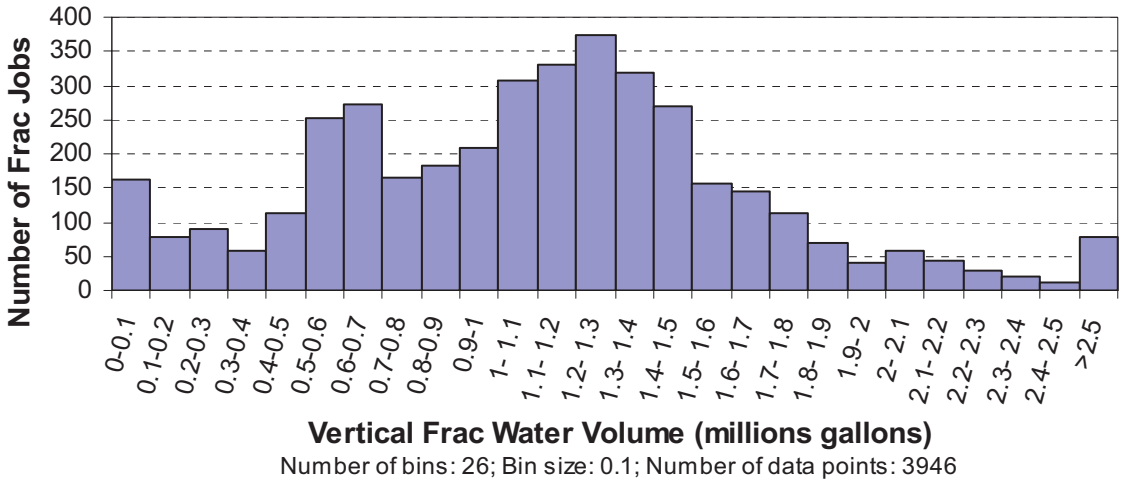


(a)

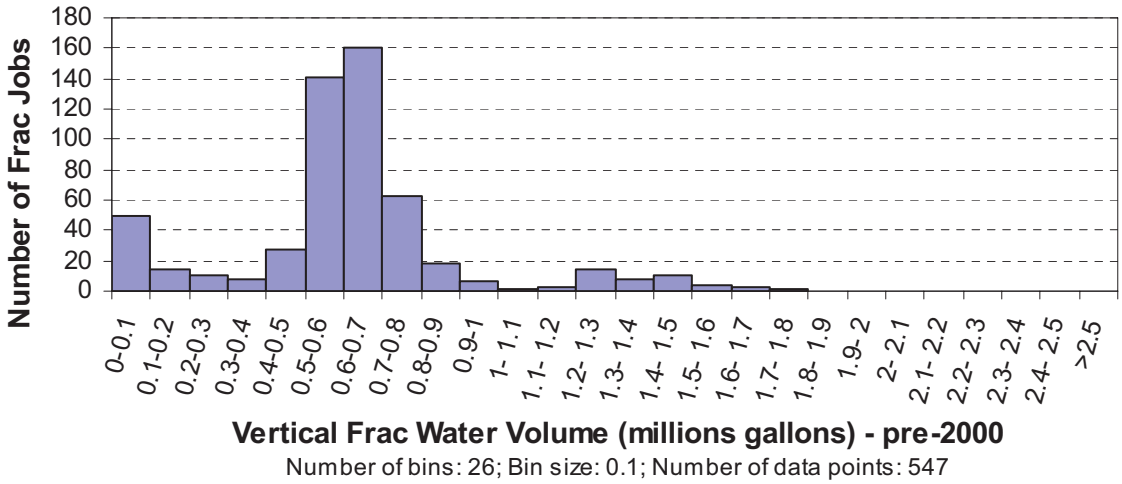


(b)

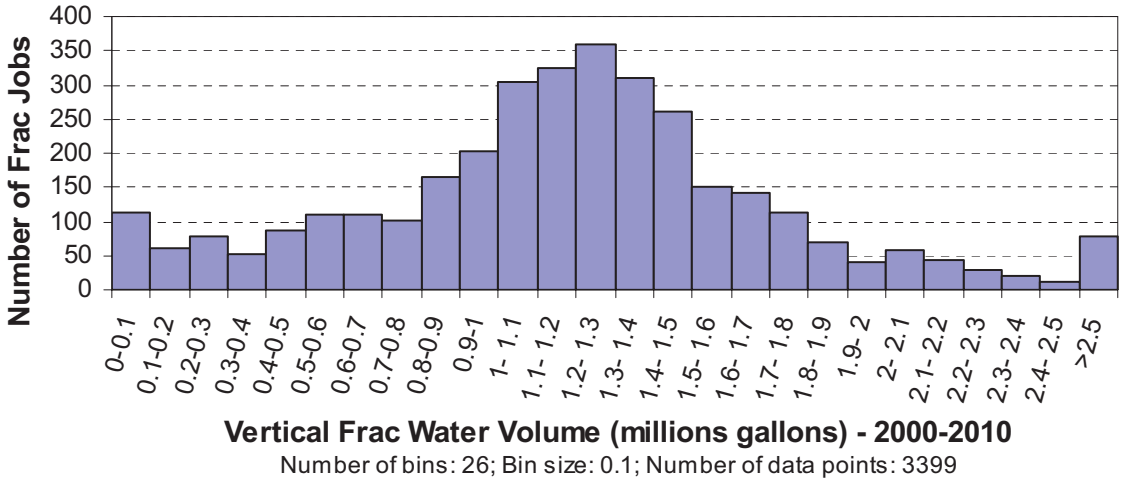
Figure 29. Barnett Shale – Annual number of frac jobs superimposed to annual average, median, and other percentiles of individual well frac water use for (a) vertical wells, and (b) horizontal wells.



(a)

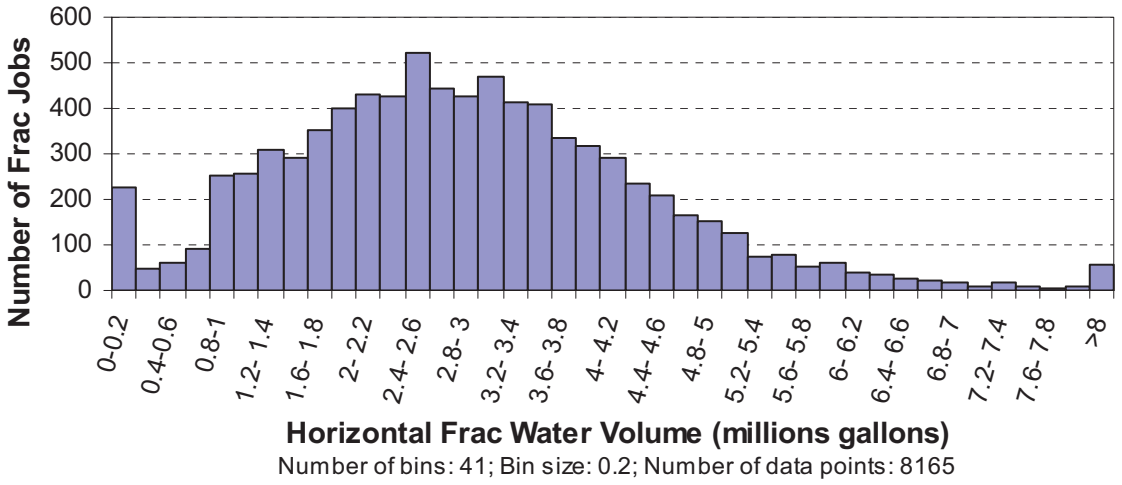


(b)

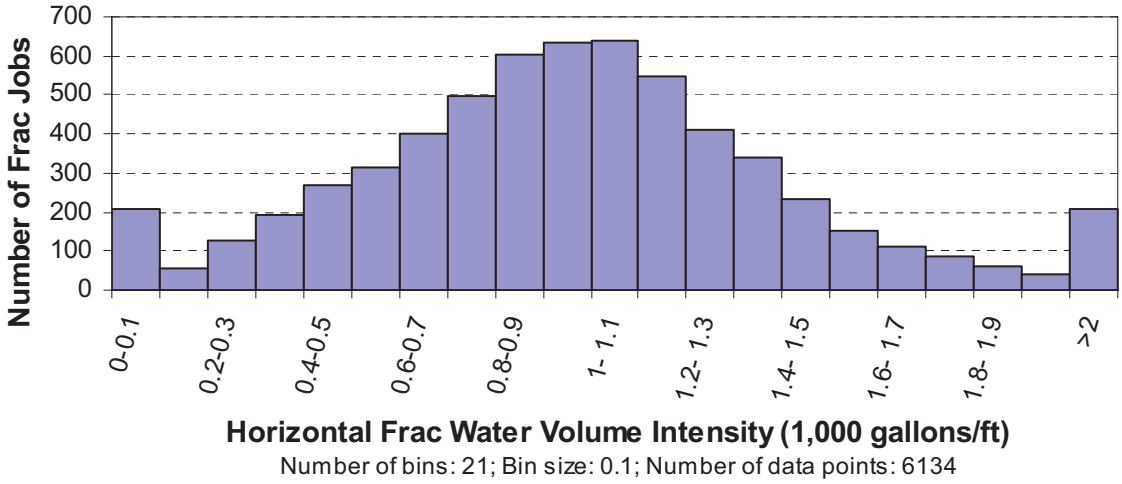


(c)

Figure 30. Barnett Shale— Histograms of frac water volume for vertical wells for (a) all wells, (b) pre-2000 wells, and (c) 2000–2010 wells

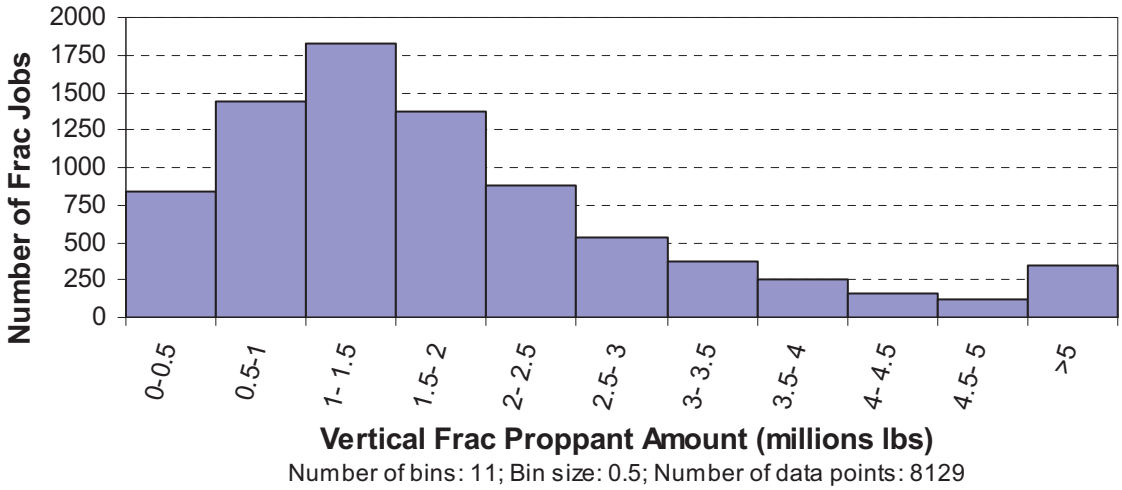


(a)

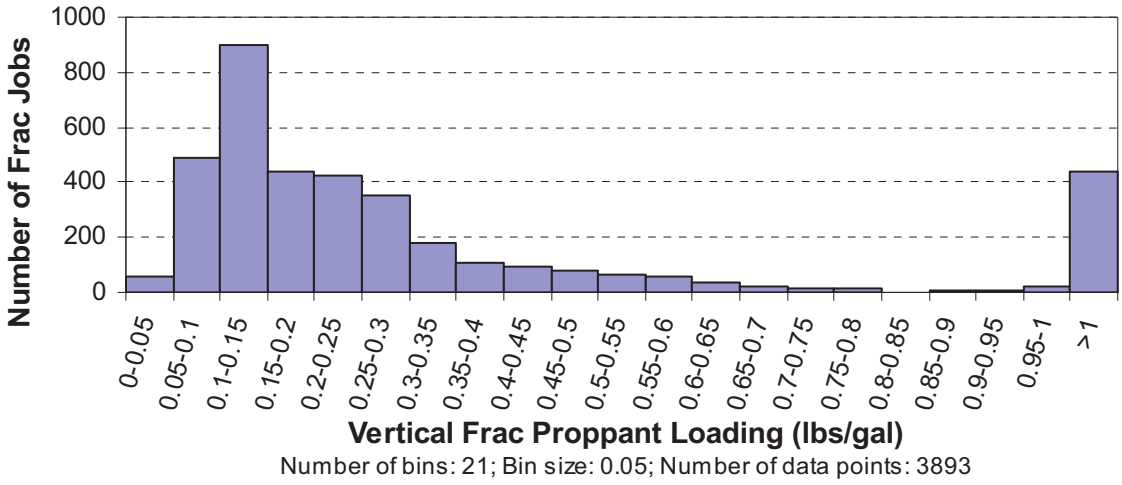


(b)

Figure 31. Barnett Shale—frac water use: (a) total volume, (b) intensity in 1,000 gal/ft

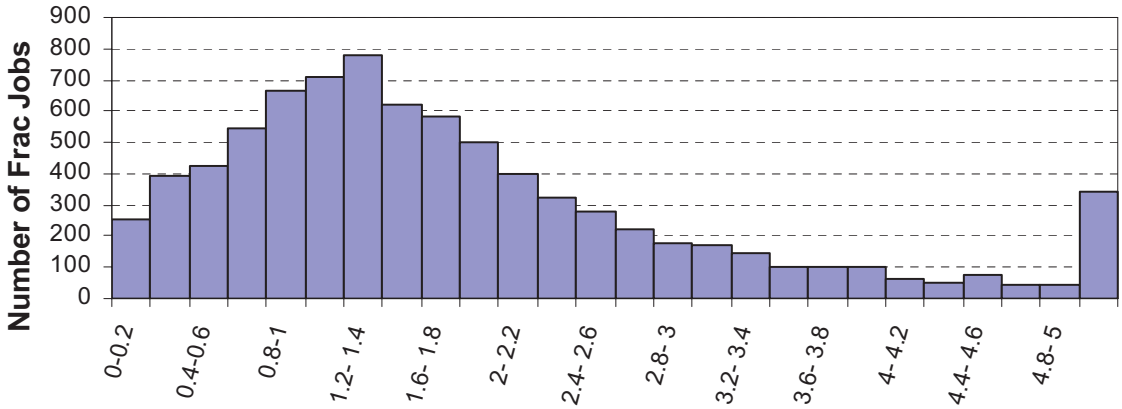


(a)

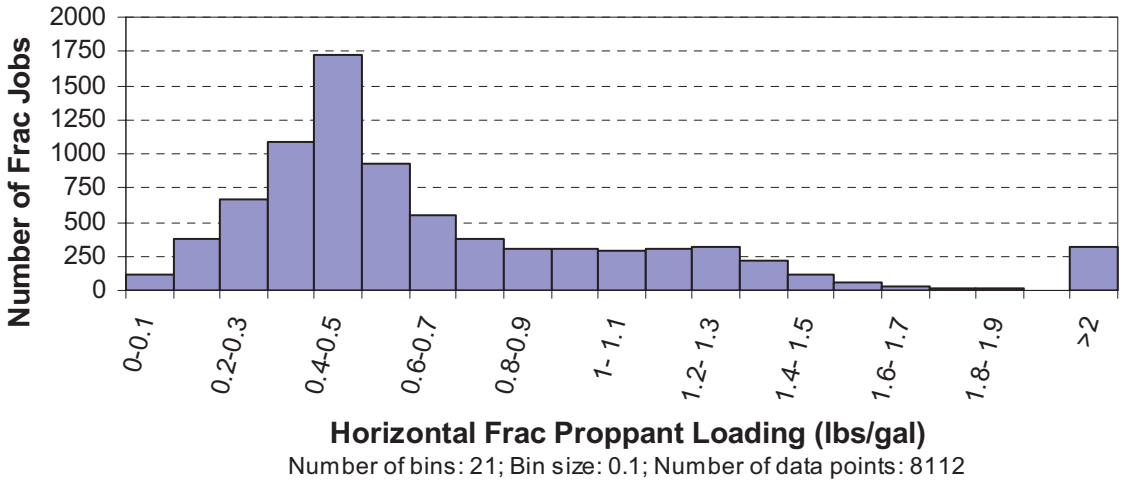


(b)

Figure 32. Barnett Shale—vertical well: (a) total proppant amount and (b) proppant loading

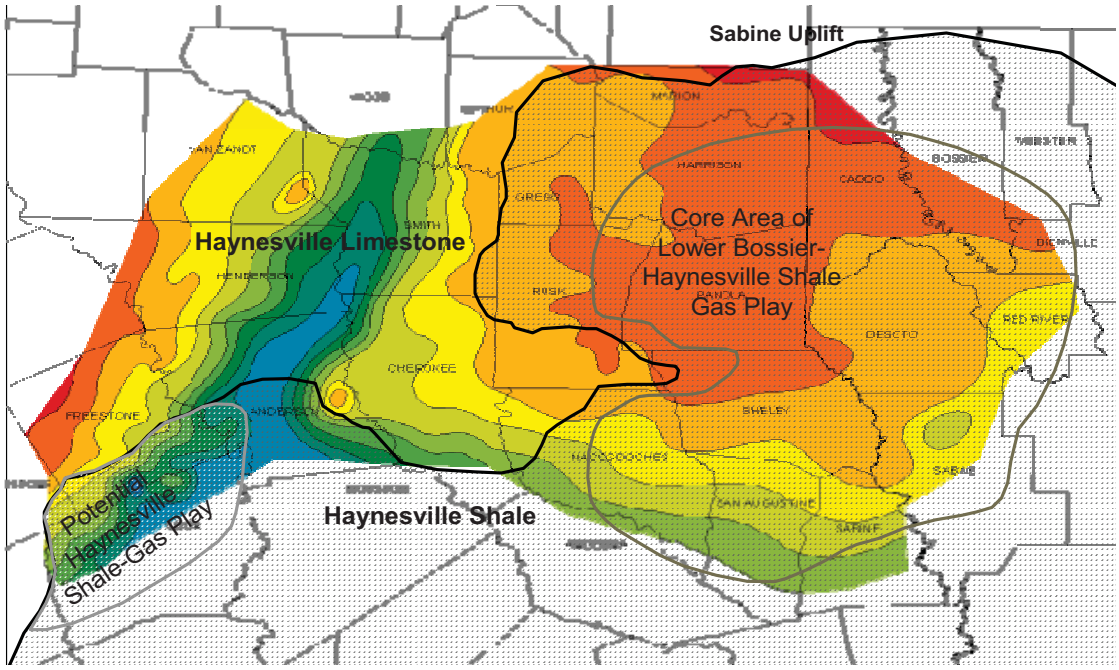


(a)



(b)

Figure 33. Barnett Shale—Horizontal well: (a) total proppant amount and (b) proppant loading



Source: courtesy Dr. Wang, BEG

Figure 34. Haynesville Shale footprint

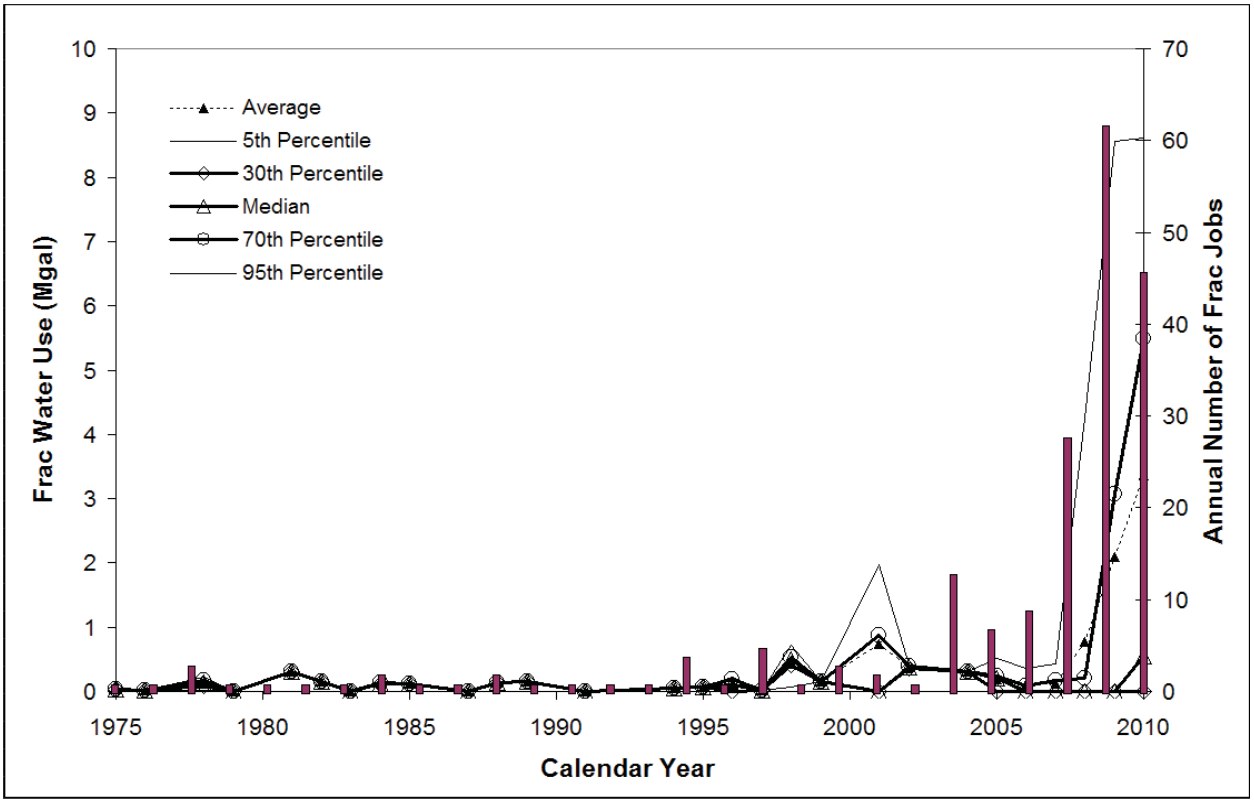


Figure 35. Haynesville Shale—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

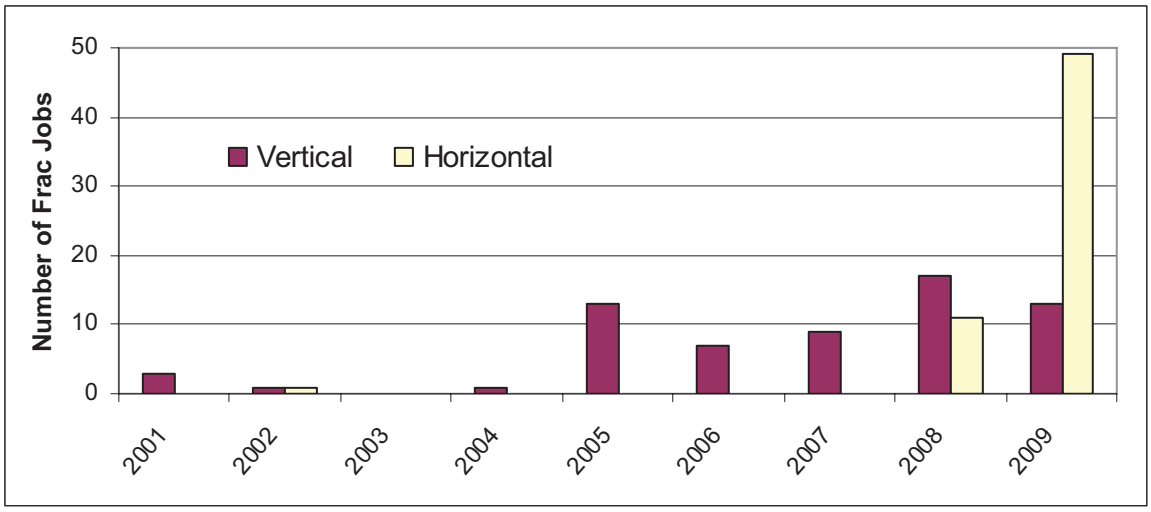
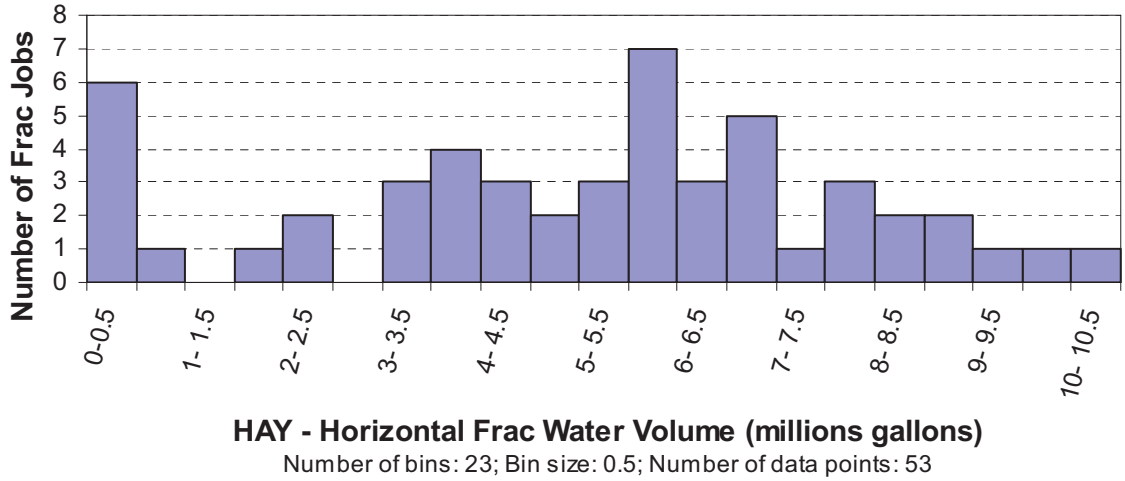
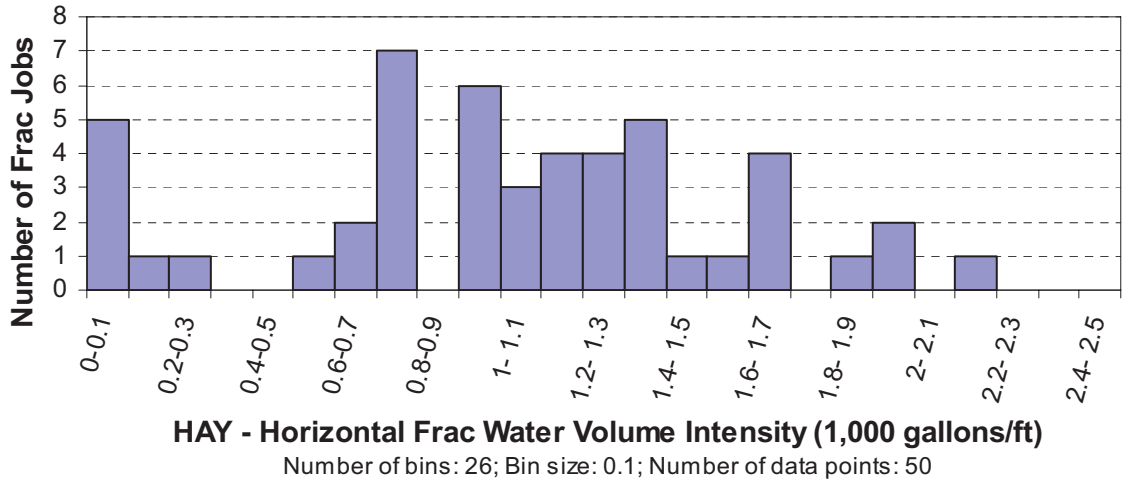


Figure 36. Haynesville Shale—vertical vs. horizontal and directional wells through time

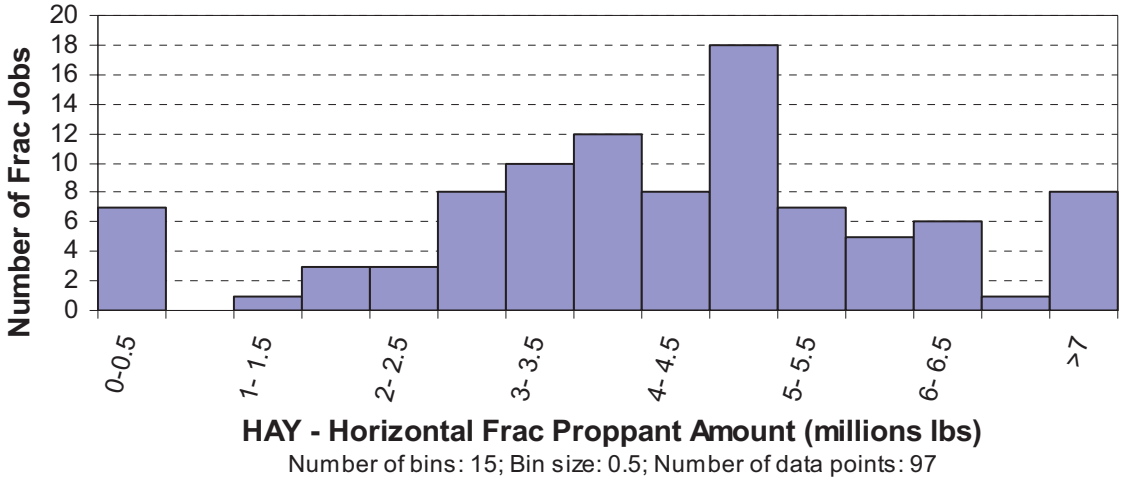


(a)

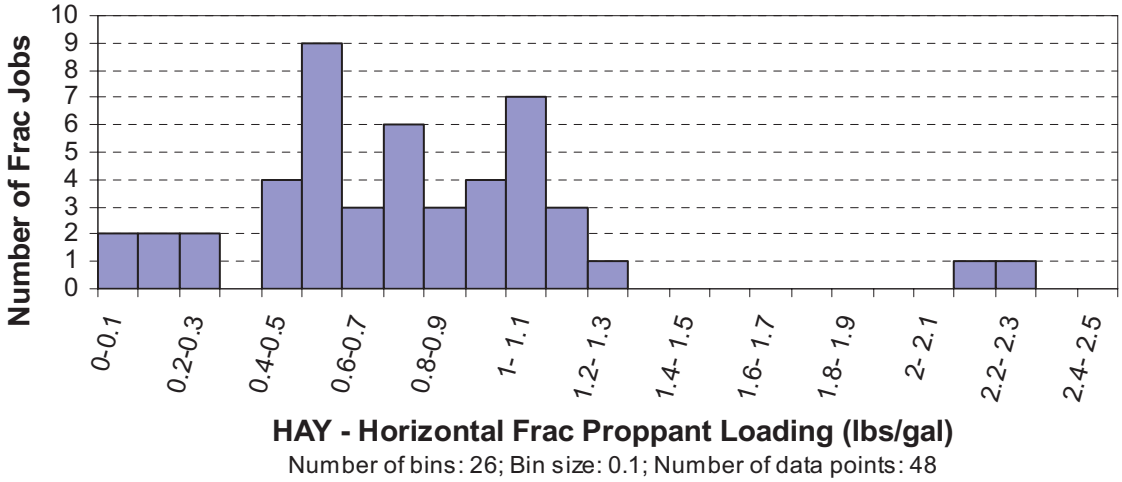


(b)

Figure 37. Haynesville—horizontal well frac water use: (a) total volume; (b) intensity in 1,000 gal/ft (2008 and beyond)

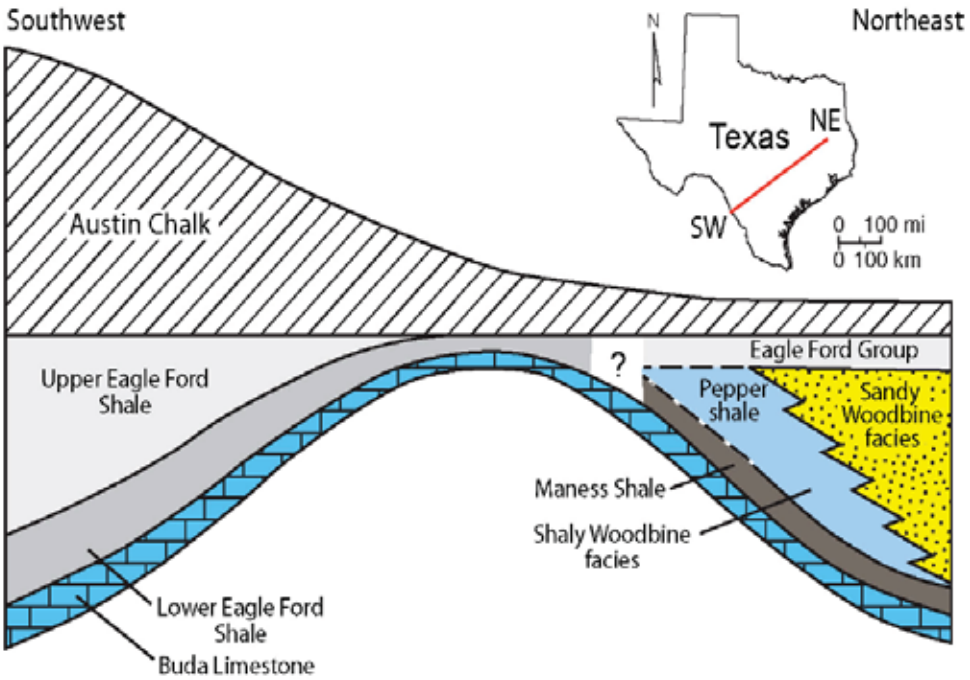


(a)



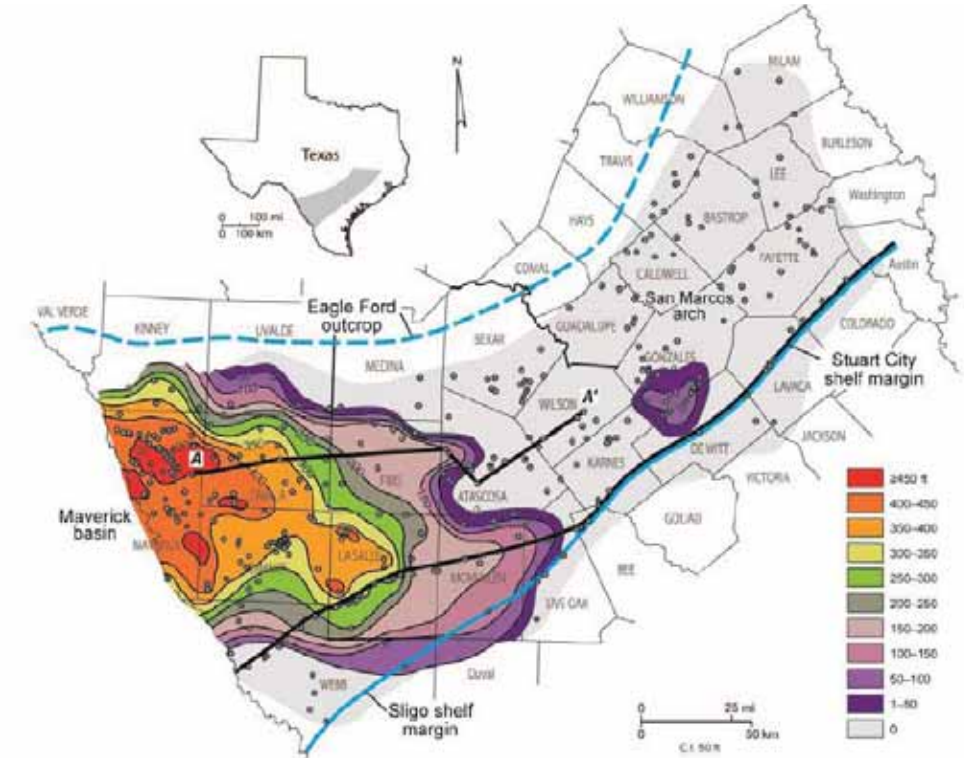
(b)

Figure 38. Haynesville—horizontal well: (a) total proppant amount and (b) proppant loading (2008 and beyond)



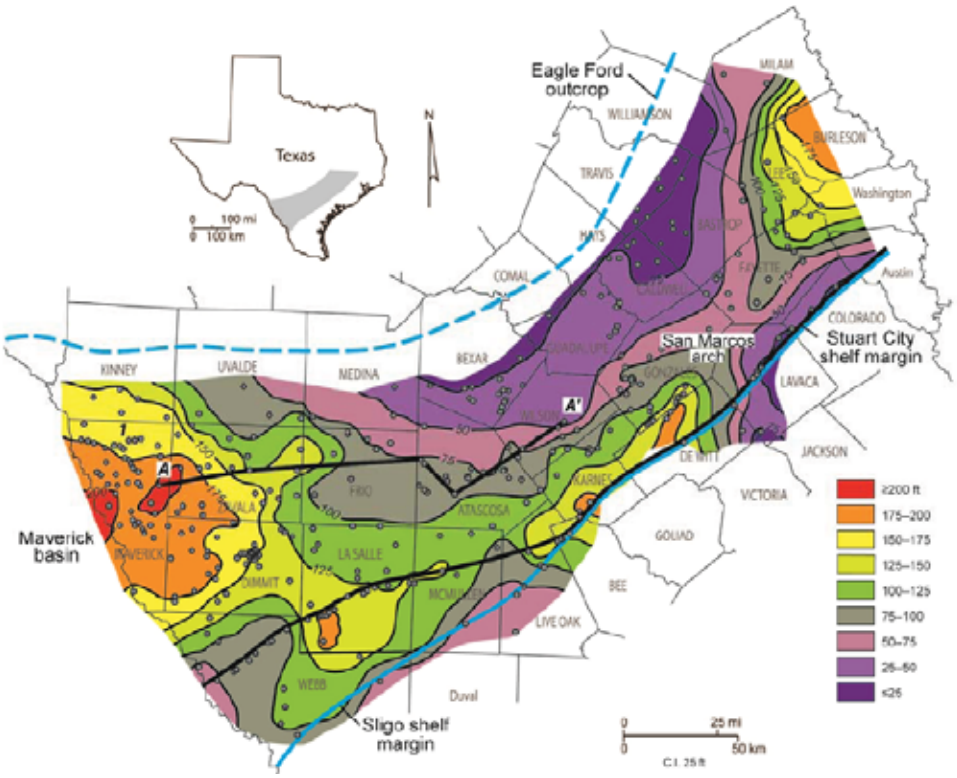
Source: Hentz and Ruppel (2010, Fig. 9)
Note: cross section hangs on top of Eagle Ford; top of Eagle Ford shallower in East Texas Basin than in Maverick Basin to the southwest

Figure 39. SW-NE schematic strike cross section illustrating regional lithostratigraphic relationships across the Eagle Ford play area



Source: Hentz and Ruppel (2010, Fig. 7)

Figure 40. Isopach map of upper Eagle Ford Shale



Source: Hentz and Ruppel (2010, Fig. 6)

Figure 41. Isopach map of lower Eagle Ford Shale

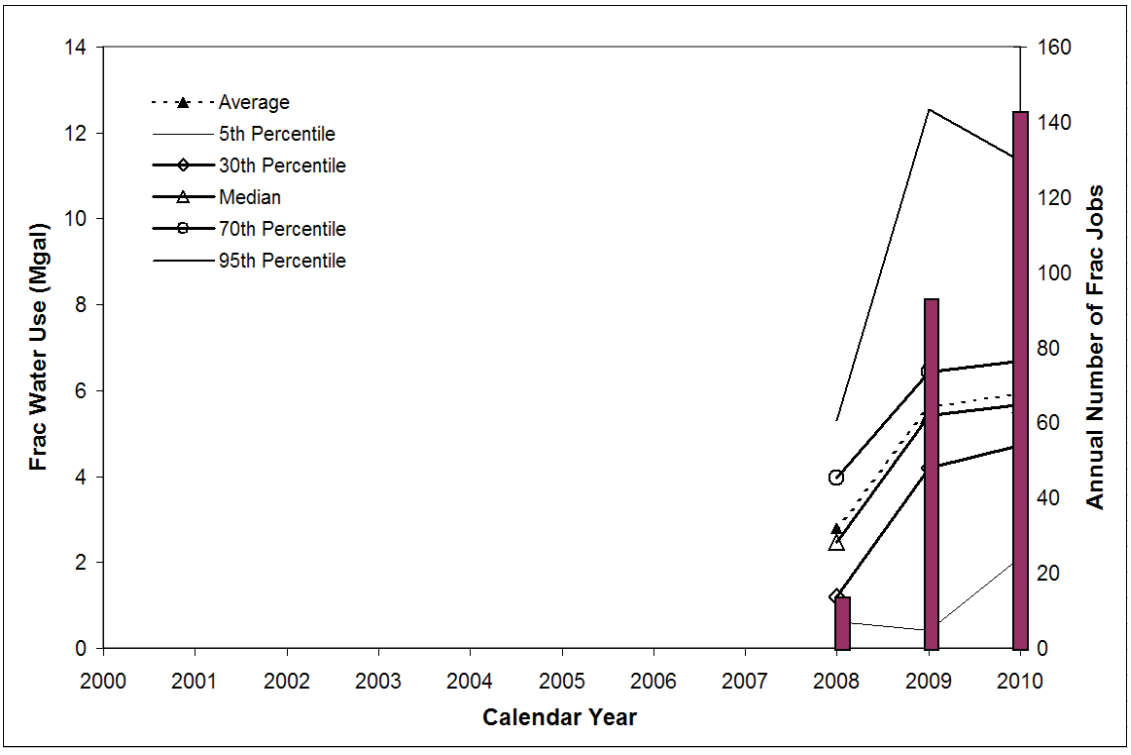


Figure 42. Eagle Ford Shale—Annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

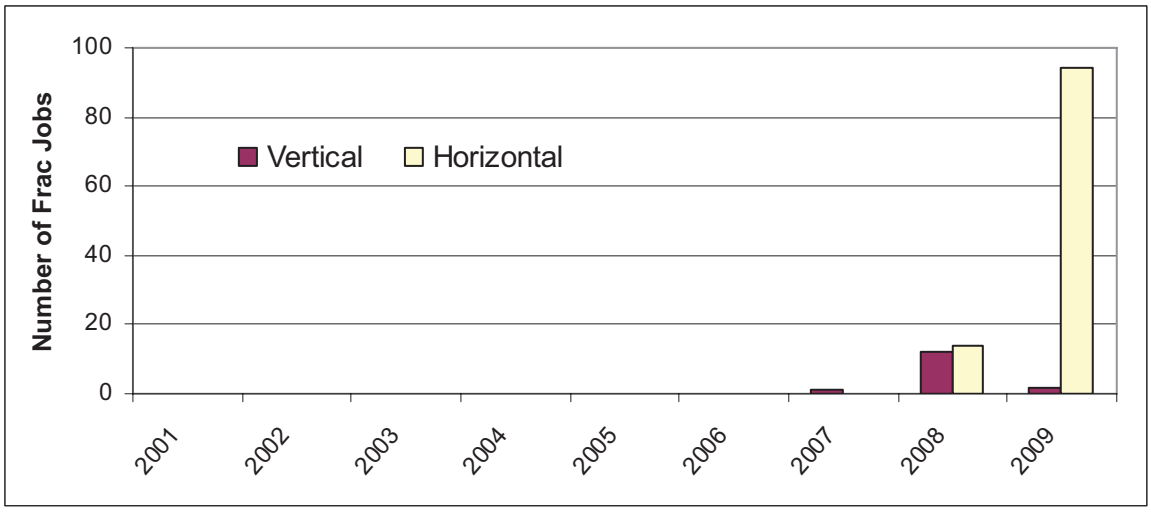
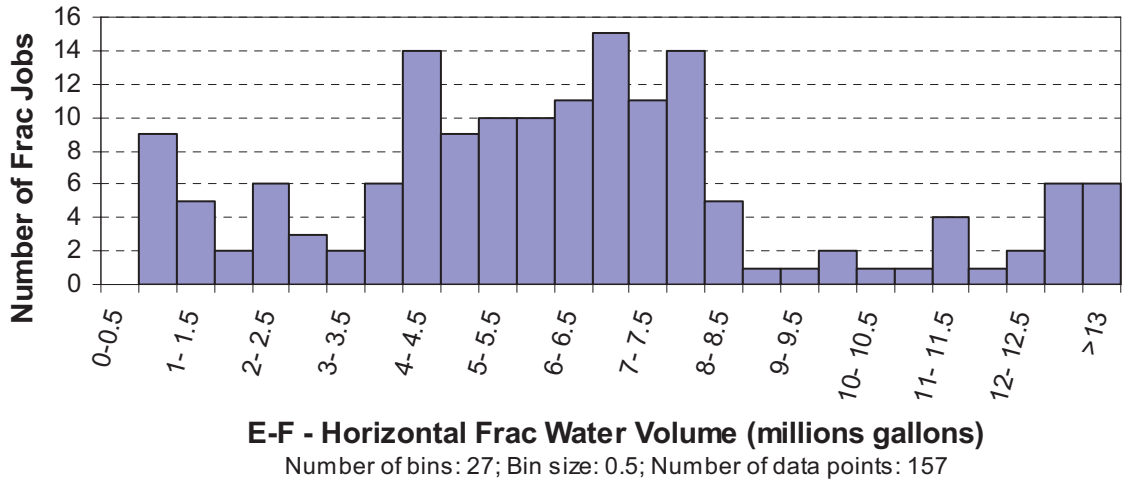
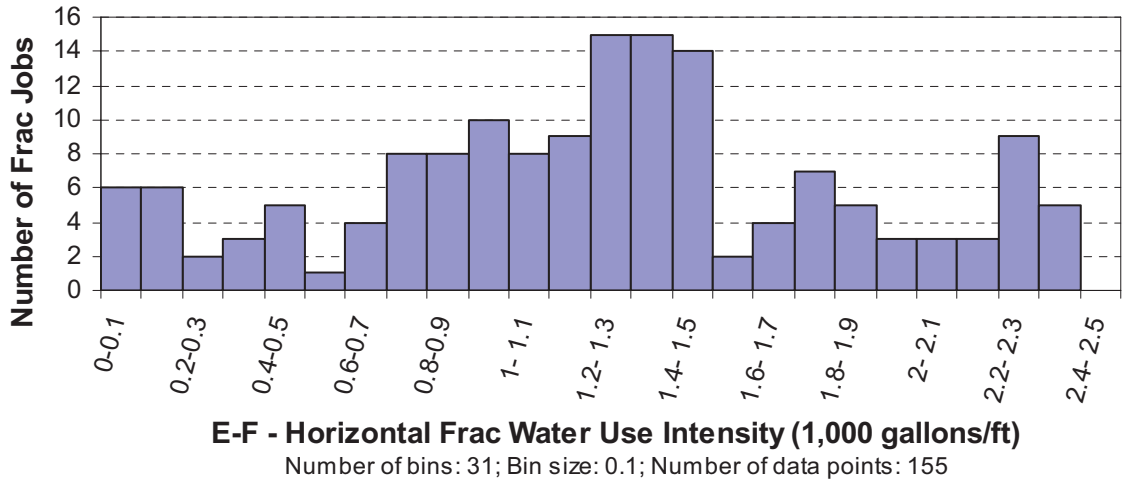


Figure 43. Eagle Ford Shale—vertical vs. horizontal and directional wells through time

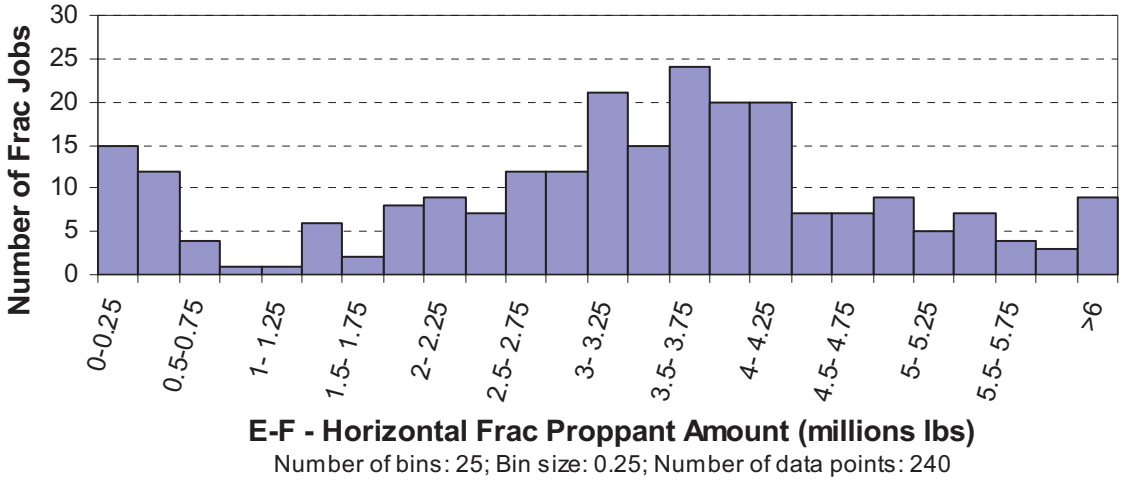


(a)

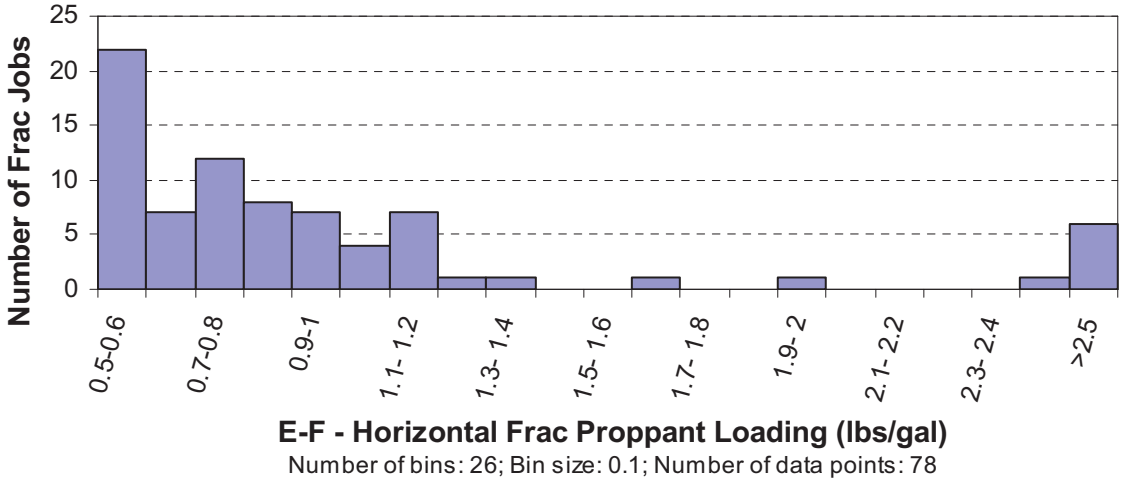


(b)

Figure 44. Eagle Ford—horizontal well frac water use: (a) total volume; (b) intensity in 1,000 gal/ft (2008 and beyond)

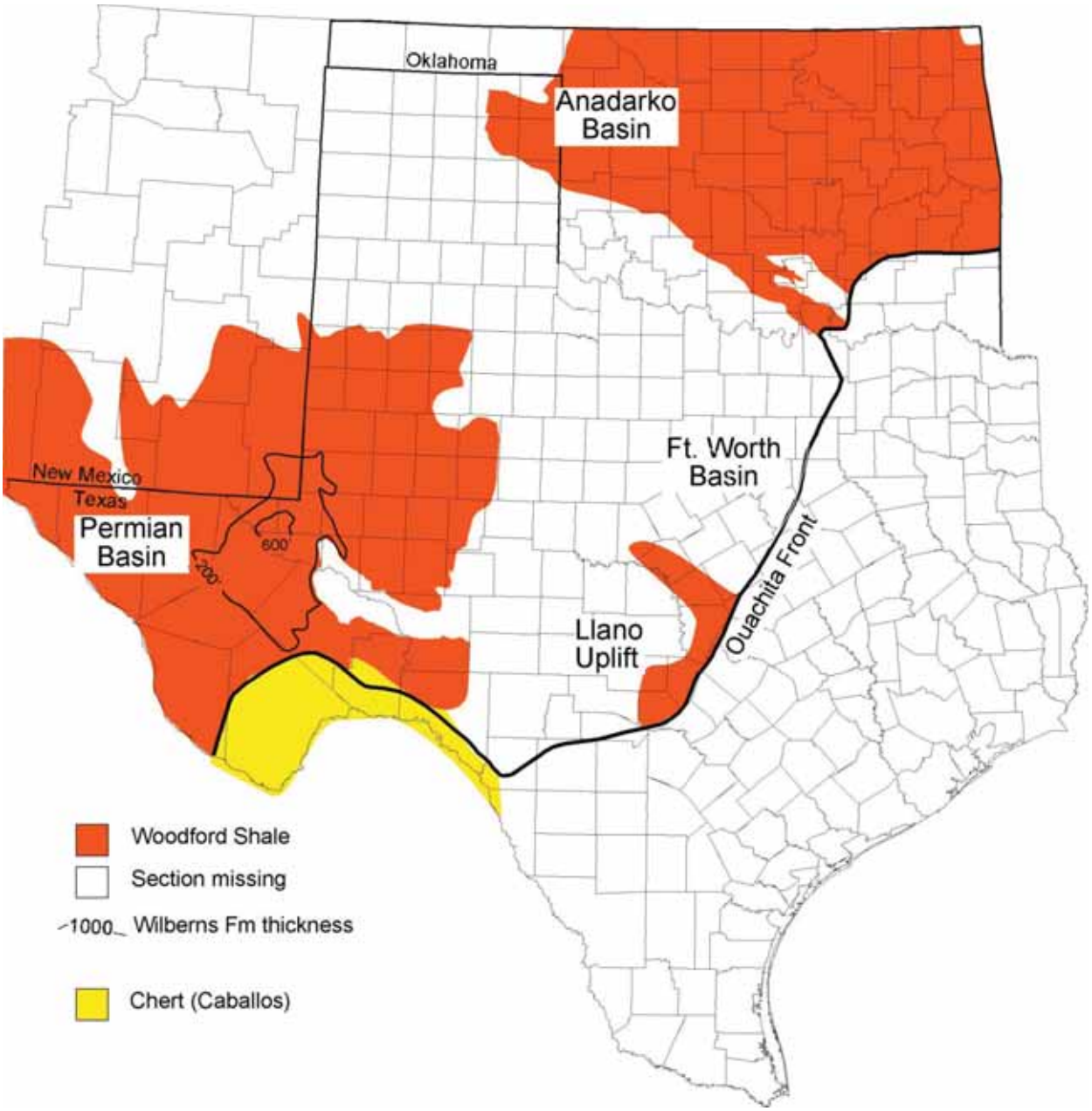


(a)



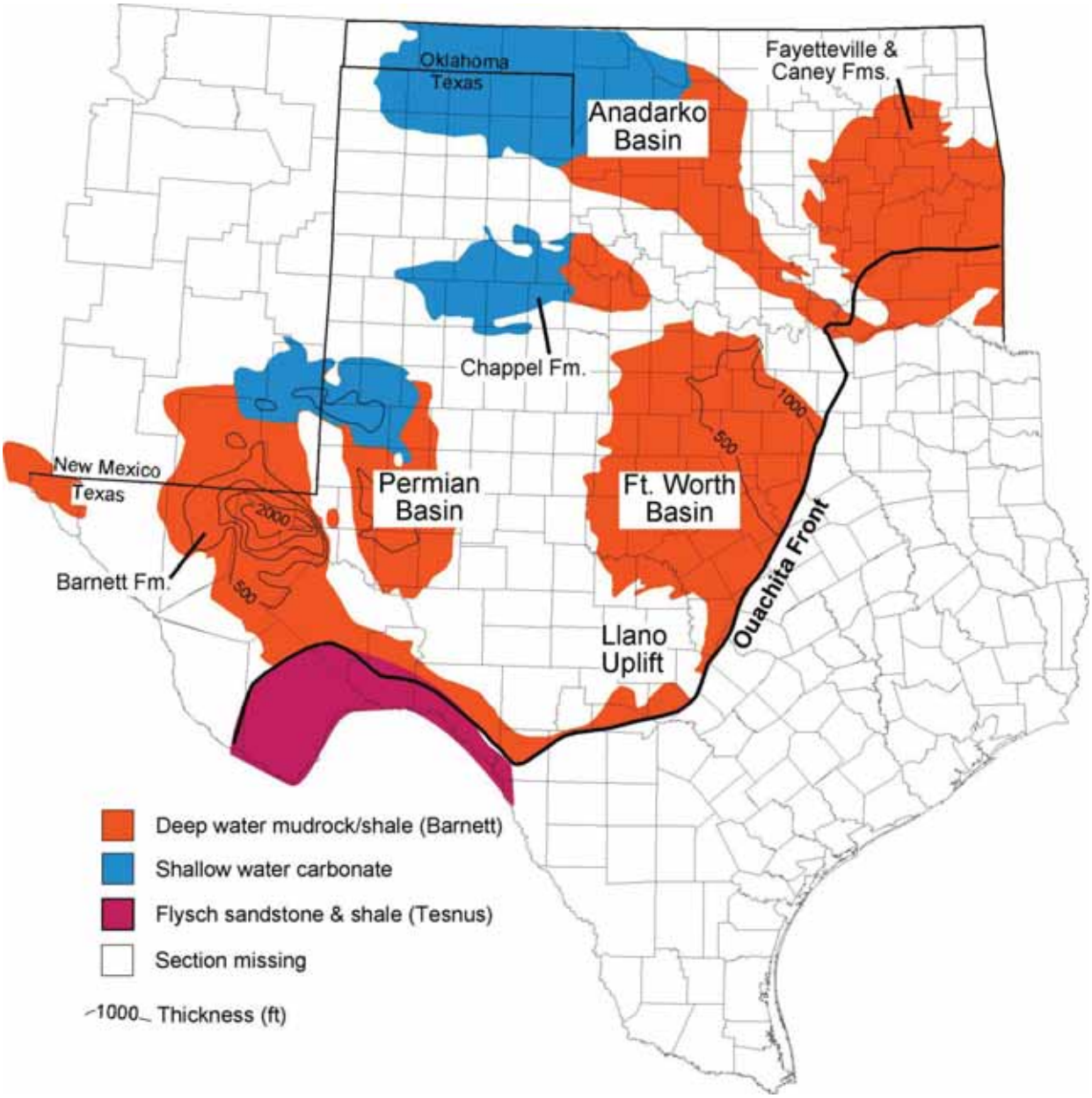
(b)

Figure 45. Eagle Ford—horizontal well: (a) total proppant amount and (b) proppant loading (2008 and beyond)



Source: Craig et al. (1979) modified by Stephen Ruppel and mudrock group (BEG)
Note: plot also displays thickness of the Wilberns Formation of Cambrian age

Figure 46. Woodford (Upper Devonian) occurrences in Texas



Source: Craig et al. (1979) modified by Stephen Ruppel and mudrock group (BEG)

Figure 47. Mississippian (including Barnett) facies distribution

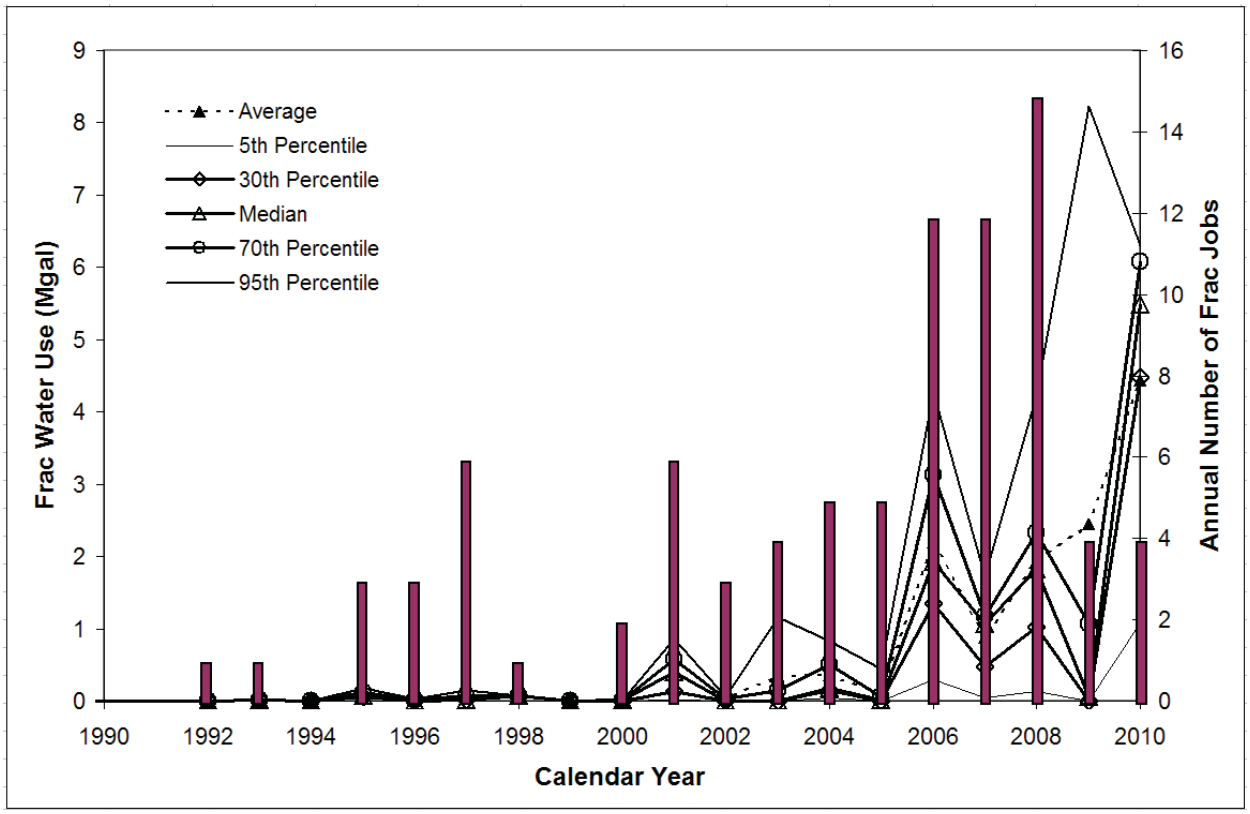


Figure 48. Woodford-Pearsall-Barnett PB—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

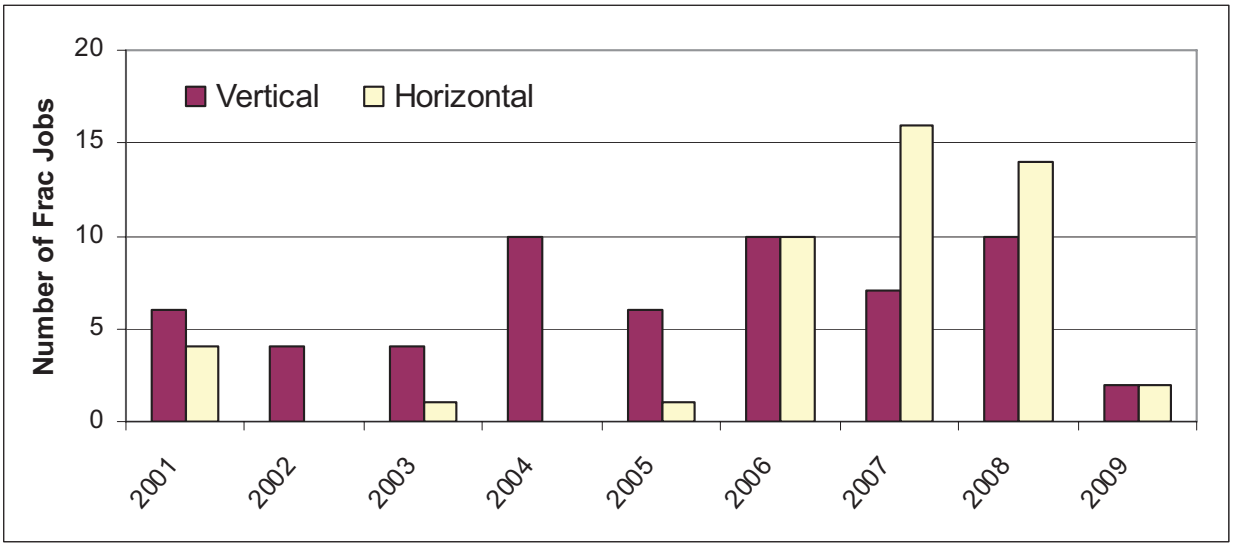


Figure 49. Woodford-Pearsall-Barnett PB—vertical vs. horizontal and directional wells through time

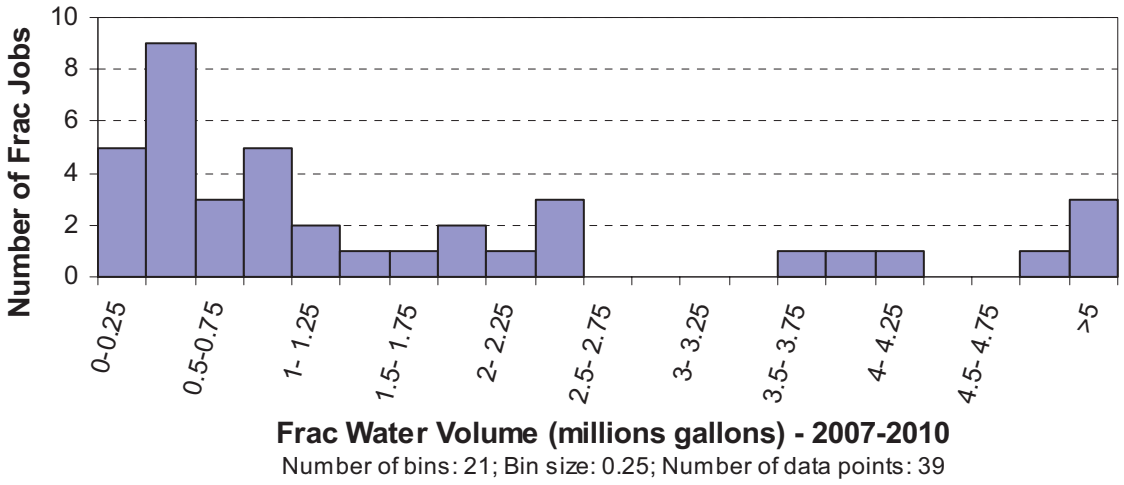


Figure 50. Woodford-Pearsall-Barnett PB horizontal and vertical well frac water use

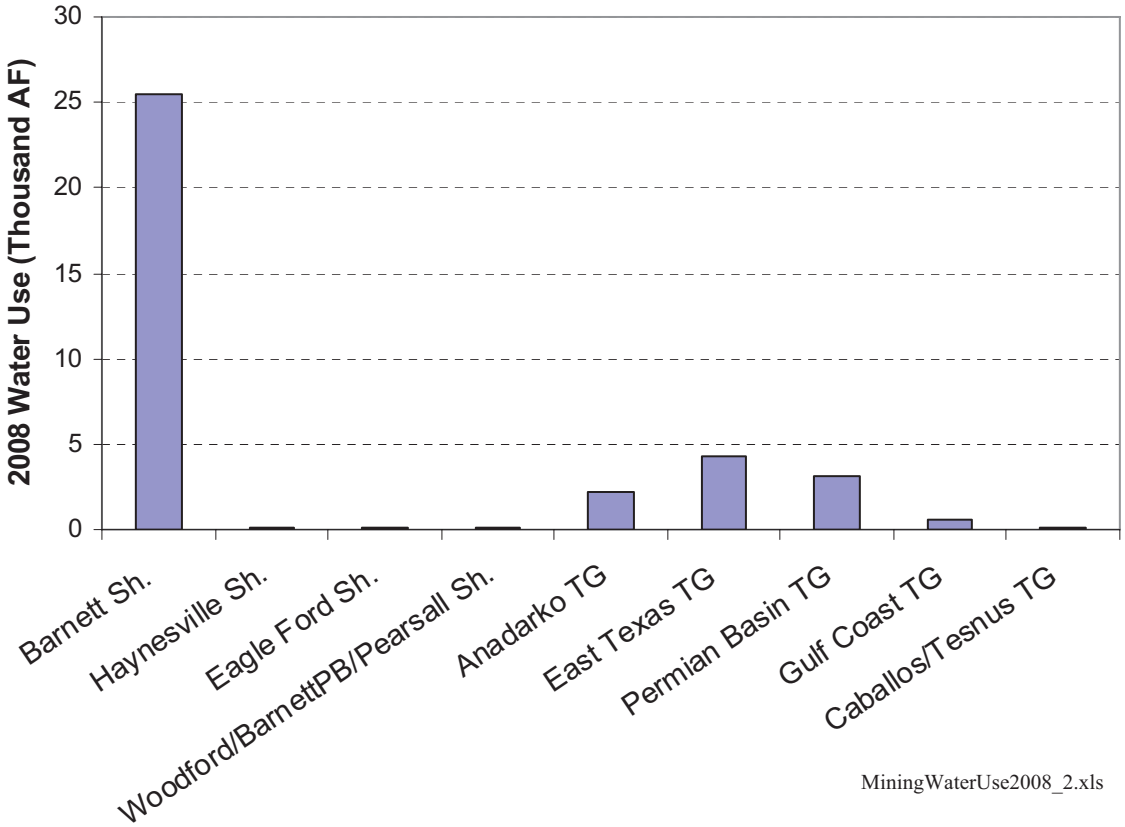


Figure 51. Water use for well completion in gas shales and tight formations (2008)

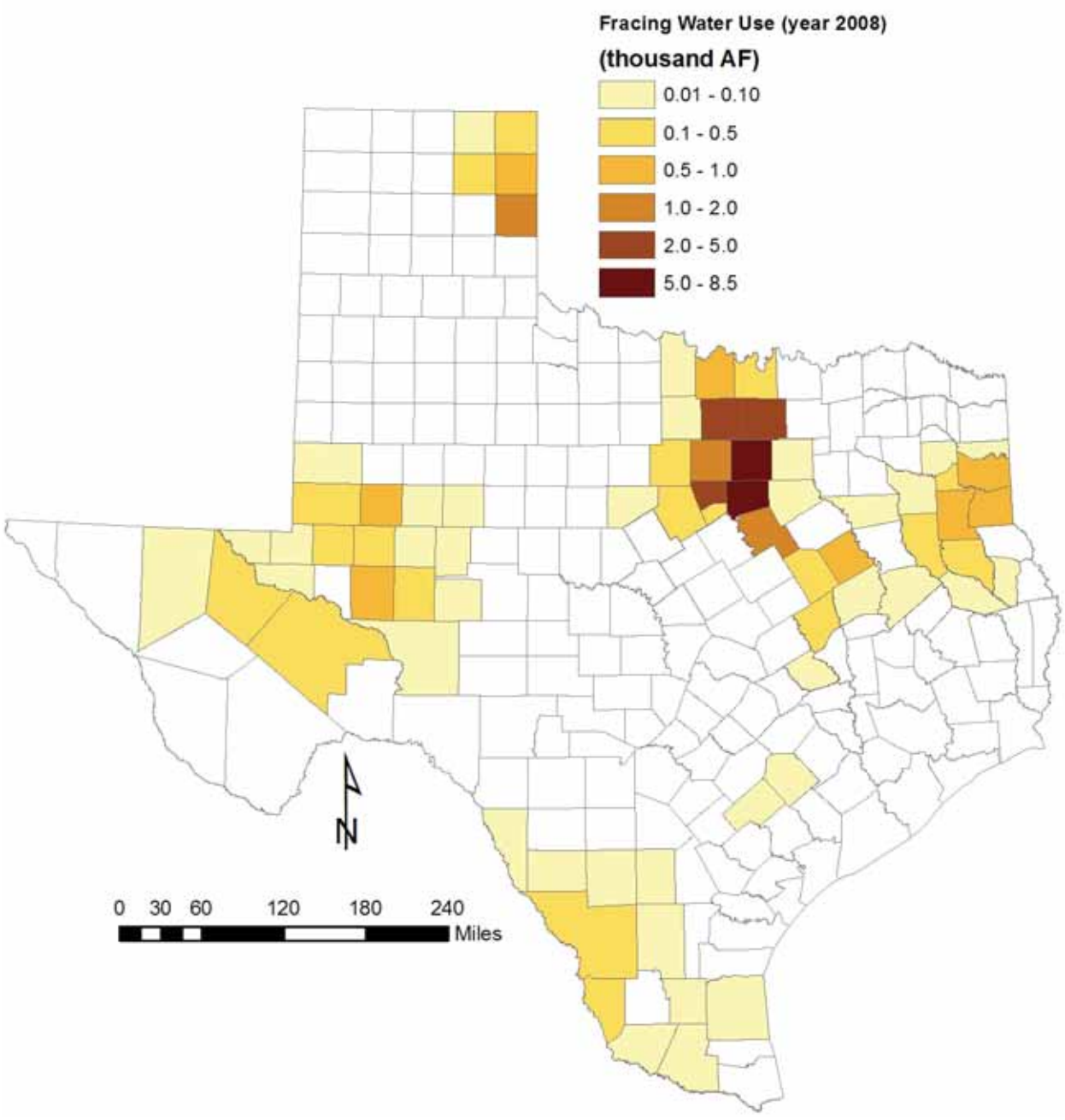


Figure 52. County-level fracing water use (2008)

4.1.3 Tight Reservoirs

Tight-sand plays are more numerous than shale-gas plays and have a longer history, going back to the 1950s and early days of the frac technology. In each basin, many formations have been fraced one time or another, and in this report they are grouped by rock type and geological affinity. BEG published many reports in the 1980s and 1990s in collaboration with GRI (Gas Research Institute, now GTI) related to tight-gas hydrocarbon accumulations. Extended summaries were presented by Finley (1984) and then Dutton et al. (1993), who considered the following Texas tight gas plays: Travis Peak (Hosston) Formation and Cotton Valley Sandstone in East Texas, Cleveland Formation and Cherokee Group in the Anadarko Basin in the Texas Panhandle, Olmos Formation in the Maverick Basin of South Texas, and the so-called Davis sandstone in the Fort Worth Basin (informal unit of the Atoka Group) (Figure 53). They were chosen because they were major gas producers at the time. Dutton et al. (1993) added the Vicksburg Formation and Wilcox Group along the Gulf Coast, the Granite Wash to the Anadarko Basin, the Morrow Formation in the Permian Basin, and the Canyon Sands in the Val Verde Basin. An observation made about many of these tight reservoirs is that low permeability is diagenetic and is caused by pore occlusion rather than depositional due to a clay matrix. In opposition to the gas shales previously discussed, tight sands are conventional in that they form reservoirs and local accumulations (Dutton et al., 1993, p. 5). A map by EIA (Figure 23b) cites them all, but with inaccurate footprints.

4.1.3.1 Anadarko Basin

Sediments of the Anadarko Basin occur mostly in Oklahoma, but its western section is located in the northern Texas Panhandle, including Gray, Hansford, Hemphill, Hutchinson, Lipscomb, Ochiltree, Oldham, Roberts, Sherman, and Wheeler Counties. The Anadarko Basin contains a thick (>18,000 ft) accumulation of siliciclastics and carbonate sediments resulting from the deposition of large volumes of arkosic sediments eroded from the Amarillo Uplift (Ambrose et al., 2010). These sediments are overlain and interfingered by carbonate and sandy deposits of the Marmaton Group and Cleveland Formation (Hentz and Ambrose, 2010). Most of the historical tight gas occurs within the thick undifferentiated interval of the so-called Granite Wash of Pennsylvanian and Permian age. Formations of similar age, such as the Caldwell, Cherokee, Cleveland, and Marmaton, contain tight-gas reservoirs as well as oil.

The basin has seen several cycles of activity since the 1950s, as evidenced by its fracing history (Figure 54b). However, the wells were vertical and the fracing water volumes were small (<0.1 Mgal/well) (Figure 54a). Since 2008, the frac water volume has increased to an average of **0.4 Mgal/well** (Figure 54a) but with a very long tail (Figure 55a). More recently, deviated vertical (directional) and horizontal have been developed in the basin (multimodal histogram of Figure 54b). Average water intensity is ~450 gal/ft (Figure 54c) with a broad mode. Both horizontal and vertical wells have been growing (Figure 56). The formation described as the Granite Wash has been fraced the most often, followed by the Cleveland Formation (Figure 57). In 2008, **2.22 thousand AF** of water was used for fracing purposes.

4.1.3.2 East Texas Basin

The East Texas Basin, sometimes incorporated into the Gulf Coast Basin in high-level regional studies, is a clearly individualized feature in northeast Texas with thick sediments of mostly Cretaceous age. It consists of a deep trough aligned in Anderson and Smith Counties (East Texas Salt Basin) and two flanks with formations of similar age but not necessarily of similar lithology

on each side (Table 11). The eastern flank abuts the Sabine Uplift over the Texas-Louisiana state line. The Travis Peak (also called Hosston) Formation (Early Cretaceous) and the Cotton Valley Sandstone (Late Jurassic) have been historical targets and producers in the tight-gas category, most of the activity being confined east of the trough, although many opportunities also exist farther west. The Cotton Valley Sandstone (Figure 58) has a spatial distribution similar to that of the Haynesville Shale. It consists of multiple generally low-permeability sand layers interspersed with shaly material. So that the reservoir could drain efficiently, well spacing has been reduced to 20 acres in many places (Baihly et al., 2007). Cotton Valley is the formation currently being fraced the most, followed by the Travis Peak Formation (Figure 60), although several other formations are also being stimulated, such as the Bossier and the Pettet Formations.

Most of the wells are vertical, although the proportion of horizontal wells is growing (Figure 59). Fracing took off in the 1990s, as it did in other tight formations, with a sharp increase in average water use in recent years (Figure 61)— **0.9 Mgal** and **3 Mgal/well** for vertical and horizontal wells, respectively (Figure 62). In 2008, the East Texas Basin used a total of **4.26 thousand AF** of water for fracing purposes.

4.1.3.3 Fort Worth Basin

The Fort Worth Basin hosts the Barnett Shale and is home to the areally extensive and highly productive Pennsylvanian fan-delta sandstone and conglomerate play (Kosters et al., 1989) (likely sources from the Barnett). Formations include Atoka and Bend Conglomerate (Thompson, 1982). This area has not been traditionally an area with significant tight-gas accumulations. Dutton et al. (1993) mentioned an interval called the Davis Sandstone, but it does not seem to be of significance, given the few wells possibly fraced recently in this interval (Table 8). In addition, any completion would be dwarfed by the Barnett Shale.

4.1.3.4 Permian Basin

The Permian Basin contains a thick accumulation of sediments from Cambrian to Permian age on a Precambrian basement. Despite its long hydrocarbon production history (>30 Bbbl, or about half the state's overall oil production) as compiled according to play by Dutton et al. (2005a,b), the basin still contains important reserves because <30% of the OOIP has been produced (Dutton et al, 2005a, p. 343). Most of the Permian Basin is in the oil window, although significant amounts of gas may exist deeper. Major operators have been content to focus on the abundant oil resources (Figure 63). The classical division of the Permian Basin into the Delaware Basin, Central Basin Platform, and Midland Basin, from west to east (to which the Eastern Shelf can be added), holds only for Permian and Pennsylvanian times (Table 12, Figure 64). At earlier periods, the Permian Basin area was not individualized in basins but presented a more complex but more regionally uniform geometry, with sediments deposited before the expression of the Delaware and Midland Basins. This geological history allows for grouping of the many series described in the IHS database into logical larger groups. However, techniques used by the operators respond more to the nature of the rock than to its age.

The Delaware Basin is in general deeper than the Midland Basin (on the other side of the Central Basin Platform) for a formation of the same age. For example, Bone Spring, Clear Fork, and Spraberry are formations of equivalent age (Figure 65). Similarly the Delaware Mountain Group in the Delaware Basin is equivalent to the San Andres-Grayburg on the Central Basin Platform and in the Midland Basin. Carbonates dominate the platform sediments, but clastics and calcareous mudrocks are more prevalent in the basins.

In Texas, the Delaware Basin includes Culberson, Reeves, and Loving Counties, as well as parts of Jeff Davis, Pecos, Ward, and Winkler Counties. The Central Platform extends from Gaines to Pecos Counties, and the Midland Basin from Terry and Lynn Counties to the north to Crockett County to the south. The Eastern Shelf parallels the Midland Basin to the east, all the way to the Bend Arch and the Fort Worth Basin and Llano Uplift.

The Delaware Basin also contains formations of interest, such as the Bone Spring Formation (also called the Avalon Shale or Leonard Shale in New Mexico) (Figure 66). It is present in Loving, Reeves, and Ward Counties, although maturity drops off quickly. The Bone Spring has seen a surge in interest but is still relatively unexplored. The Delaware Mountain Group, stratigraphically above the Bone Spring Formation, but similar in terms of lithology and broad depositional environments, has many reservoirs from shallow depth (2,500 ft) to much deeper levels (>8,000 ft). Recovery is low, <30% after secondary and possibly tertiary production (Dutton et al., 2005a, p. 312–314). The top of the gas window in the Delaware Basin is estimated to be at ~10,000 ft.

The important development of the so-called Wolfberry play in the Midland Basin corresponds to operators fracing similar rocks of stacked Spraberry, Dean, and then Wolfcamp (Figure 67), and possibly Strawn basinal deposits involving up to 12 stages in vertical wells at a depth of >7,000 ft. Spraberry/Dean reservoirs have historically had a fairly low recovery (10% of OOIP, Dutton et al., 2005a, p. 205). Most of the fracing has focused on the margins of the basin along the Central Platform and the Eastern Shelf. There has been a considerable interest in the Wolfberry play in the past few years, as illustrated by the number of recent wells (Figure 24).

Canyon Sands in the Val Verde Basin, a southeastern extension of the Permian Basin south of the Ozona Arch (Crockett County), were deposited in deep environments (Dutton et al, 1993, p. 122). The Canyon Sands, initially thought equivalent to the Canyon Formation in the Permian Basin, are actually mostly of Permian age (Hamlin et al., 1995, p. 4-5), although the name remains. For convenience, we also added the Devonian Caballos and Mississippian Tesnus Formations south of the Ouachita Front (Figure 46 and Figure 47) to the Permian Basin category.

Overall the Permian Basin has seen 50,000+ frac jobs in the past 50 years (Figure 68), including 18,300+ with water use >0.1 Mgal (Figure 69), and ~2,900 frac jobs with water use >0.5 Mgal, mostly in the past few years. The plots show a clear upward trend in all percentiles since 2000, with average water use approaching **1 Mgal/well** (Figure 70) with a broad distribution (once <0.1Mgal jobs are removed) (Figure 71). This is a relatively modest amount per current standards, but most of the wells are vertical (Figure 72). Many formations are being fraced, but the Spraberry/Dean in the Midland Basin, the Clear Fork in the Central Platform, and the Wolfcamp underlying both form the bulk of the frac jobs (Figure 73 and Figure 74). Devonian formations are also the subject of interest. We treated the Caballos and Tesnus Formations separately because they are located farther south, but their statistics are similar to those of other formations of West Texas, with a sharp increase in recent years (Figure 75) and an average water use at ~0.35 Mgal/well (Figure 75 and Figure 76).

In 2008, the Permian Basin (Texas section) used a total of **3.25 thousand AF** of water for fracing purposes (including 0.17 for the Caballos/Tesnus).

4.1.3.5 Maverick Basin and Gulf Coast

The Texas southern Gulf Coast province is well known for its gas-prone hydrocarbon accumulations and includes the Frio Formation, a prolific conventional gas producer, as well as

the Wilcox deltaic (Table 13; Figure 147 in Appendix C). Tight-gas formations such as Vicksburg and Wilcox Lobo tend to occur deeper (Dutton et al., 1993). The Maverick Basin, included in the Gulf Coast area for the purpose of this study, contains the Olmos Formation, another important tight-gas formation. Overall, Gulf Coast tight formations have not seen the increase in average frac water volume as seen in all other basins, despite a sharp increase in the number of frac jobs (Figure 78). The reason may be due to the lack of horizontal wells (Figure 73). Recently active plays include the Vicksburg, the Wilcox, and the Olmos Formations, which have been traditionally fraced (Figure 79). The amount of water used is low (**<0.2 Mgal/well** for the most part) (Figure 80), but the proppant amount is relatively high (Figure 81), leading to a high proppant loading (Figure 82). These plays have most likely not been swept by the new fracing technologies, but we assume that they will in the future (we assume a water use of **0.5 Mgal/well** or projections), as operators revisit older plays through refracing and infill wells.

In 2008, the Gulf Coast Basin used a total of **0.60 thousand AF** of water for fracing purposes.

4.1.3.6 Conclusions on Tight Formations

Water use for tight formation completion is less than half of that for gas shales, at 10.4 thousand AF (Table 10 and Figure 51). Table 14 lists all counties with a total use >0.001 AF in 2008. Average water use across the 84 counties (Figure 52) is~120 AF, and Wheeler County, in the Panhandle, has the highest water use at 1.07 thousand AF.

Table 11. Simplified stratigraphic column of the East Texas Basin showing commonly fraced intervals, as well as potential targets (in bold)

System	Age	Formation / Group		
			Salt Basin	
Cretaceous		**Austin Chalk***		
		Glen Rose/Fredericksburg/ Washita/Eagle Ford		
		Pearsall / Rodessa / James		
		Sligo / **Pettet***		
		Hosston/**Travis Peak***		Hosston/**Travis Peak***
		Cotton Valley*		**Cotton Valley***
Jurassic		**Bossier Sands***		**Bossier Shale***
		Haynesville Limestone		**Haynesville Shale***
		Smackover/Buckner		

Table 12. Simplified stratigraphic column of the Permian Basin showing commonly fraced intervals, as well as potential targets (in bold)

System	Age	Formation / Group		
		Delaware Basin	**Central Platform**	**Midland Basin**
Permian	Ochoan	Salado/Rustler/Dewey Lake and Dockum		
	Guadalupian	**Delaware Mountain Group* (Brushy, Cherry, & Bell Canyon)**	Queen/Seven Rivers/**Yates***/Tansill San Andres Grayburg	
	Leonardian	**Bone Spring***	Clear Fork	**Spraberry*/Dean***
	Wolfcampian	Wolfcamp Basin	Wolfcamp Platform	**Wolfcamp Basin***
Pennsylvanian		Morrow/Atoka/Strawn/Canyon/Cisco		
Mississippian		**Barnett***	N/A	Platform Carbonates **Barnett***
Devonian		**Devonian*/Woodford***		
Silurian		**Siluro-Devonian***		
Ordovician		Simpson Group/Ellenburger		
Cambrian		Wilberns		

Table 13. Simplified stratigraphic column of South Texas Gulf Coast showing commonly fraced intervals, as well as potential targets (in bold)

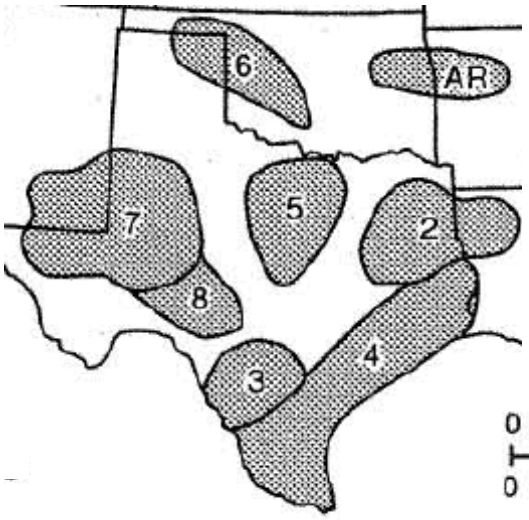
System	Age	Formation / Group
Oligocene		**Vicksburg*/Frio***
Eocene / Paleocene		**Wilcox-Lobo***/Carrizo/Queen City/Sparta/ Yegua/Jackson
Paleocene (Early)		Midway
Cretaceous		**San Miguel*/Olmos*/Escondido***
		Austin Chalk*
		Eagle Ford*
		Glen Rose/Edwards/Stuart City/Georgetown/Del Rio/Buda/
		Pearsall*
		Hosston/Sligo
Jurassic		Cotton Valley

Table 14. County-level tight-formation-completion water use (2008)

County	Water Use (thousand AF)	County	Water Use (thousand AF)	County	Water Use (thousand AF)
Andrews	0.132	Harrison	0.815	Ochiltree	0.071
Angelina	0.090	Hemphill	0.721	Panola	0.908
Bee	0.006	Henderson	0.028	Pecos	0.183
Borden	0.003	Hidalgo	0.074	Reagan	0.308
Brazoria	0.003	Houston	0.013	Real	0.002
Brooks	0.015	Howard	0.047	Reeves	0.057
Calhoun	0.003	Irion	0.062	Roberts	0.216

County	Water Use (thousand AF)	County	Water Use (thousand AF)	County	Water Use (thousand AF)
Cherokee	0.120	Jackson	0.004	Robertson	0.208
Colorado	0.002	Jim Hogg	0.002	Rusk	0.540
Crane	0.003	Kenedy	0.027	San Augustine	0.088
Crockett	0.026	La Salle	0.017	San Patricio	0.002
Culberson	0.012	Lavaca	0.018	Smith	0.052
Dawson	0.007	Leon	0.055	Starr	0.068
DeWitt	0.013	Limestone	0.264	Sterling	0.022
Dimmit	0.004	Lipscomb	0.141	Terrell	0.008
Duval	0.020	Live Oak	0.003	Terry	0.004
Ector	0.183	Loving	0.030	Upshur	0.030
Edwards	0.002	McMullen	0.044	Upton	0.999
Fort Bend	0.003	Marion	0.029	Val Verde	0.001
Freestone	0.501	Martin	0.560	Van Zandt	0.002
Frio	0.004	Matagorda	0.008	Ward	0.067
Gaines	0.018	Maverick	0.015	Webb	0.112
Glasscock	0.096	Midland	0.371	Wharton	0.006
Goliad	0.009	Mitchell	0.027	Wheeler	1.071
Gregg	0.128	Nacogdoches	0.384	Willacy	0.005
Hale	0.002	Navarro	0.004	Winkler	0.014
Hansford	0.003	Newton	0.001	Yoakum	0.005
Hardin	0.001	Nueces	0.008	Zapata	0.107

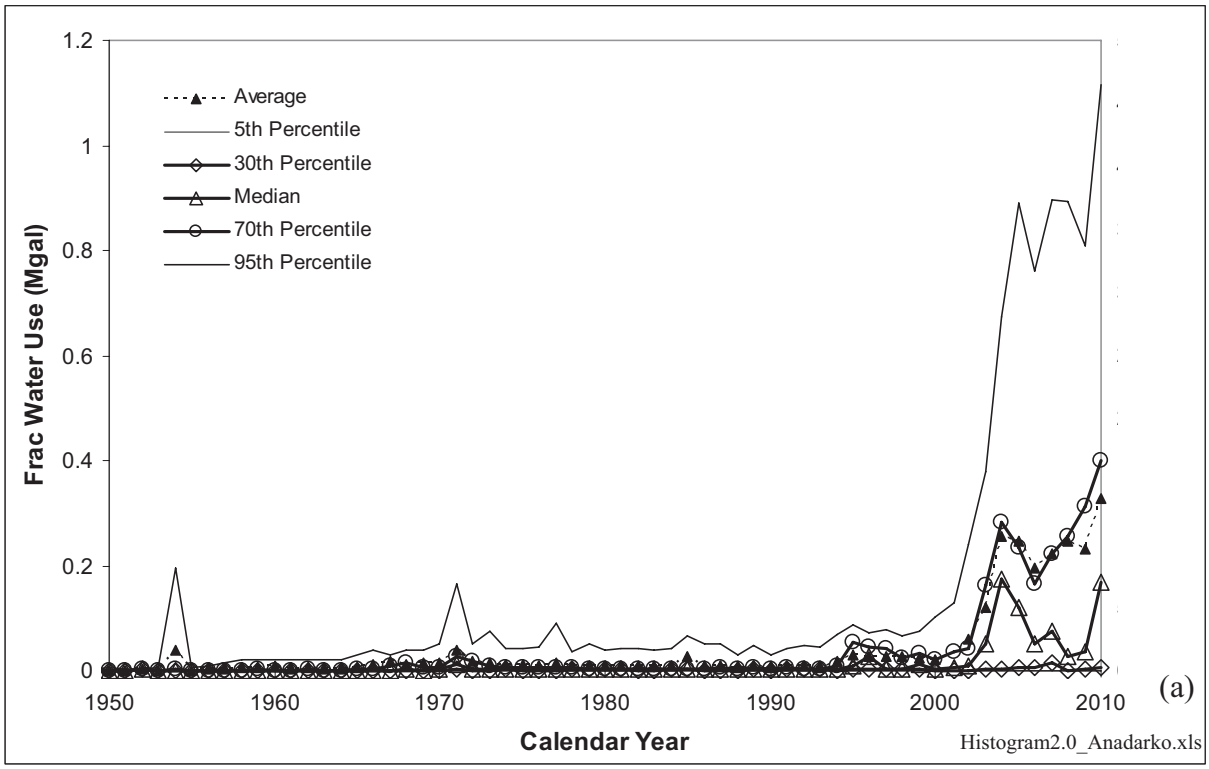
MiningWaterUse2008_2.xls



2: Travis Peak Formation and Cotton Valley Sandstone
3: Olmos Formation
4: Vicksburg Formation and Wilcox Group
5: Davis Sandstone
6: Cleveland Formation, Cherokee Group, and Granite Wash Formation
7: Morrow Formation
8: Canyon Sands

Source: modified from Dutton et al. (1993, Fig. 1)

Figure 53. Location of basins in Texas containing low-permeability sandstone with historical frac jobs



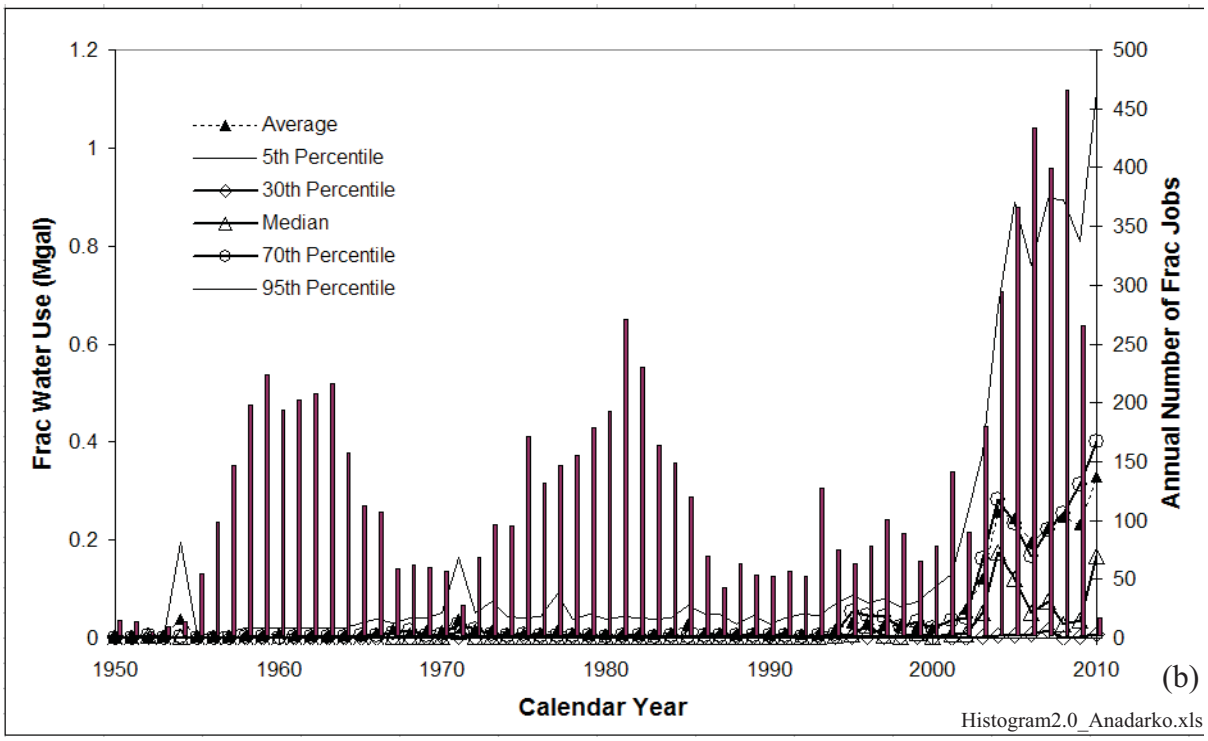
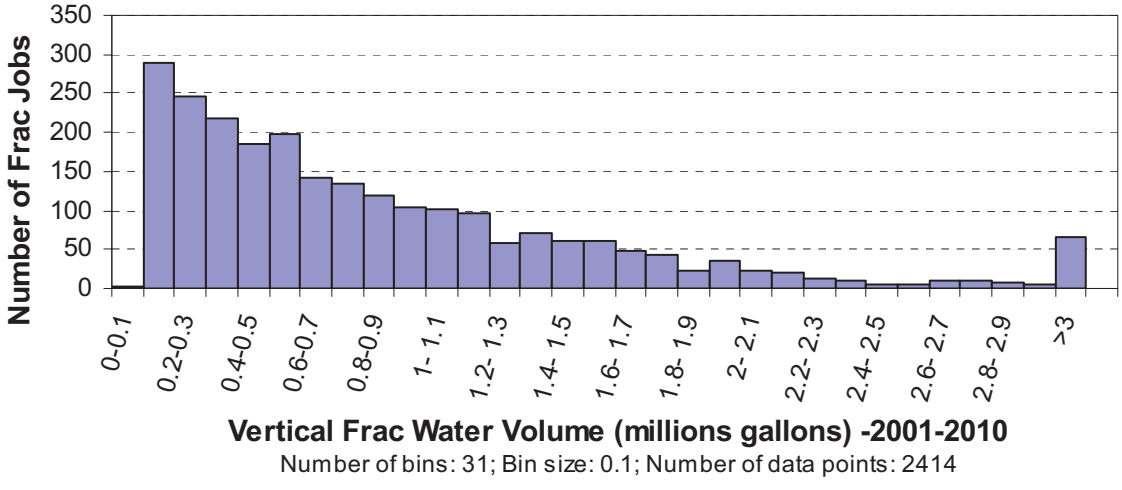
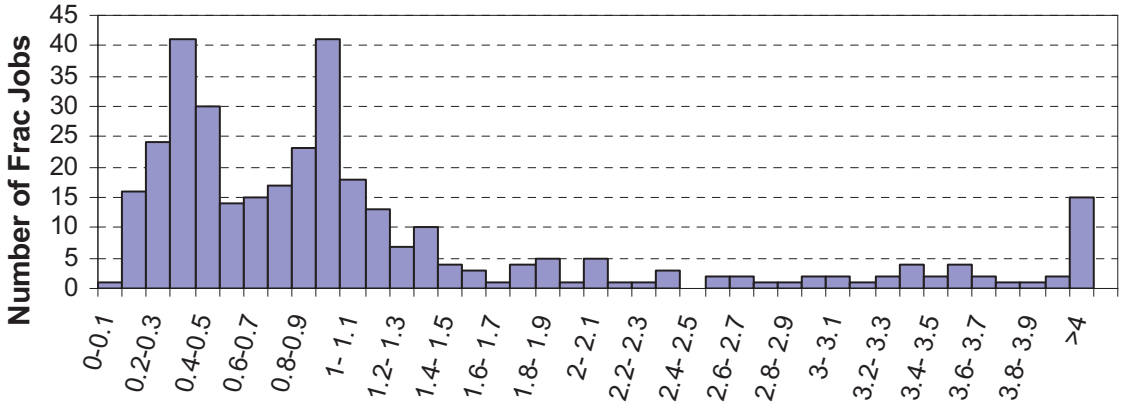


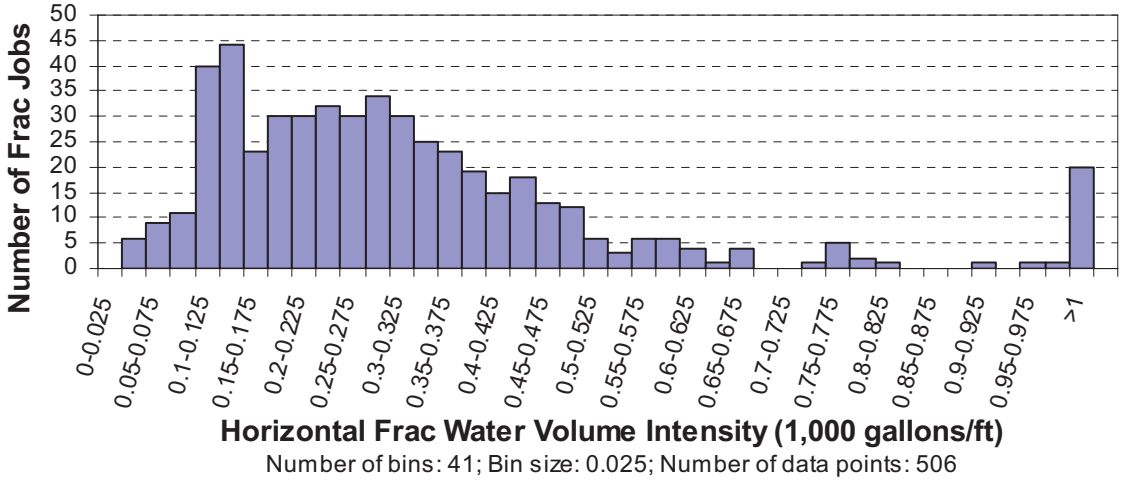
Figure 54. Anadarko Basin—annual number of frac jobs (b) superimposed on annual average, median, and other percentiles of individual well frac water use (a)



(a)



(b)



(c)

Note: (c) uses only those "H" wells for which lateral length can be computed—histograms include only those frac jobs using >0.1 Mgal.

Figure 55. Anadarko Basin—frac water use in vertical wells (a), nonvertical wells (b), and water-use intensity in selected horizontal wells (c)

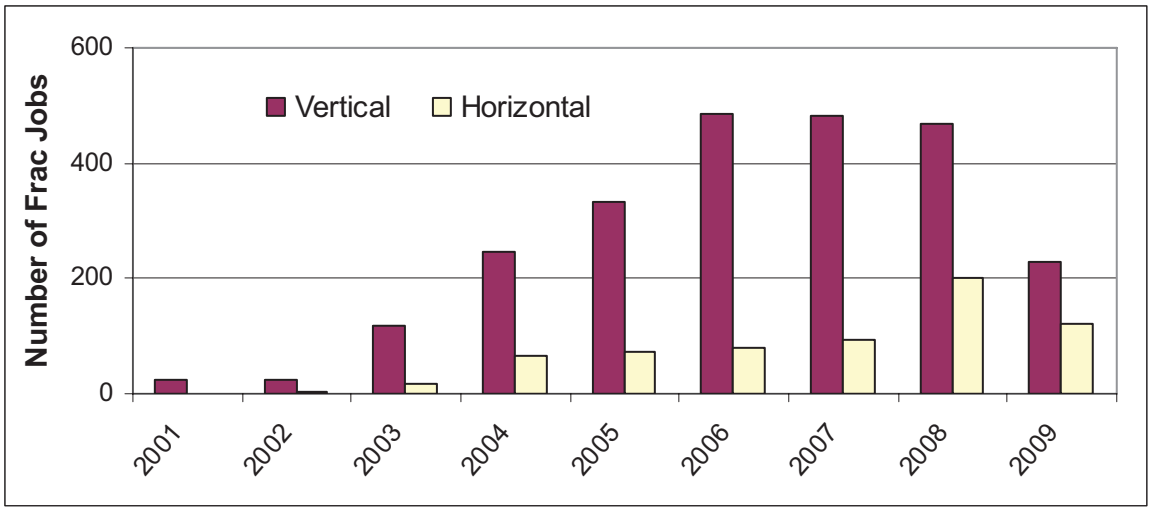


Figure 56. Anadarko Basin—vertical vs. horizontal and directional wells through time

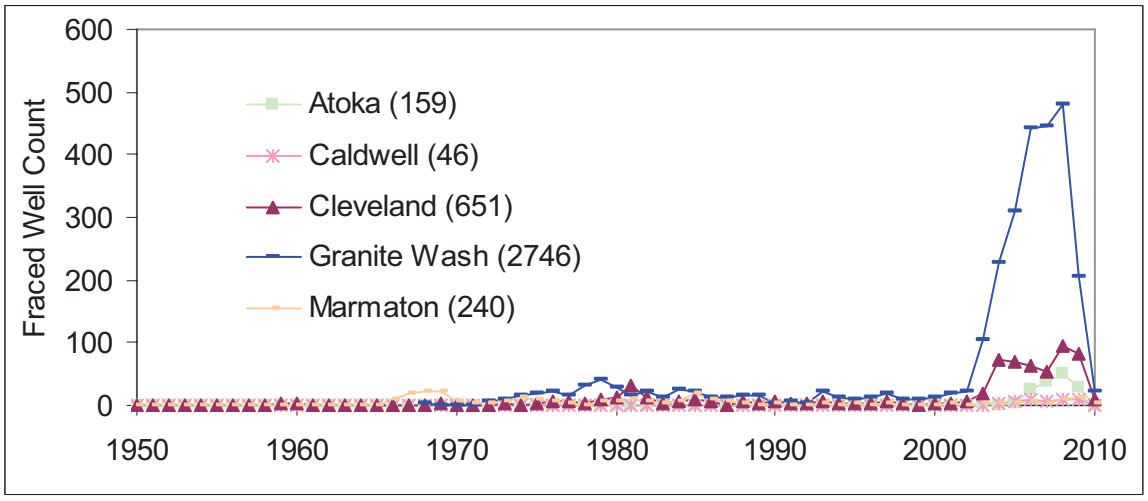
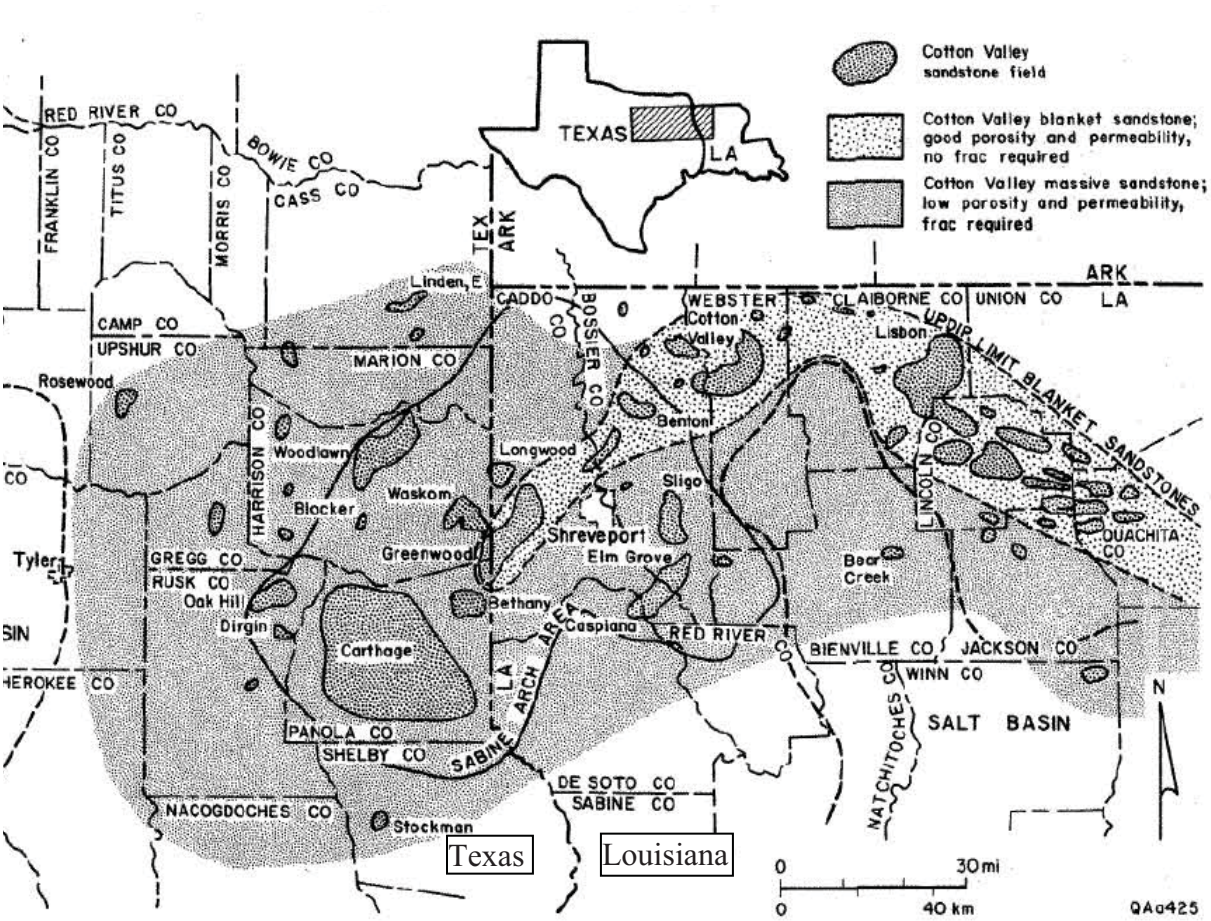


Figure 57. Anadarko Basin—fraced well count per formation



Source: Dutton et al. (1993, Fig. 24)

Figure 58. Distribution of Cotton Valley reservoir trends in East Texas

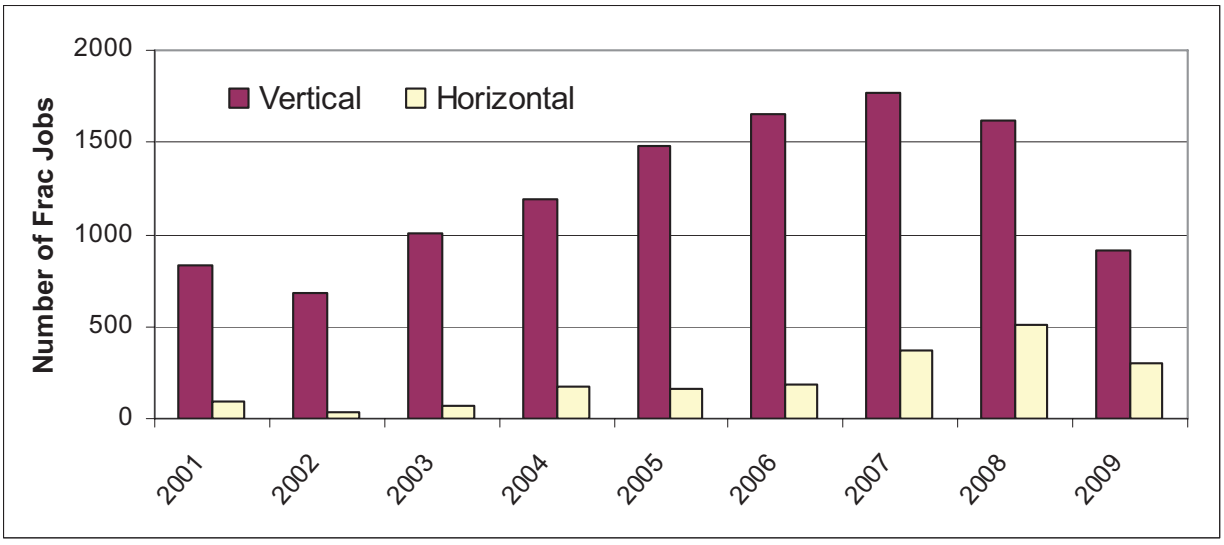
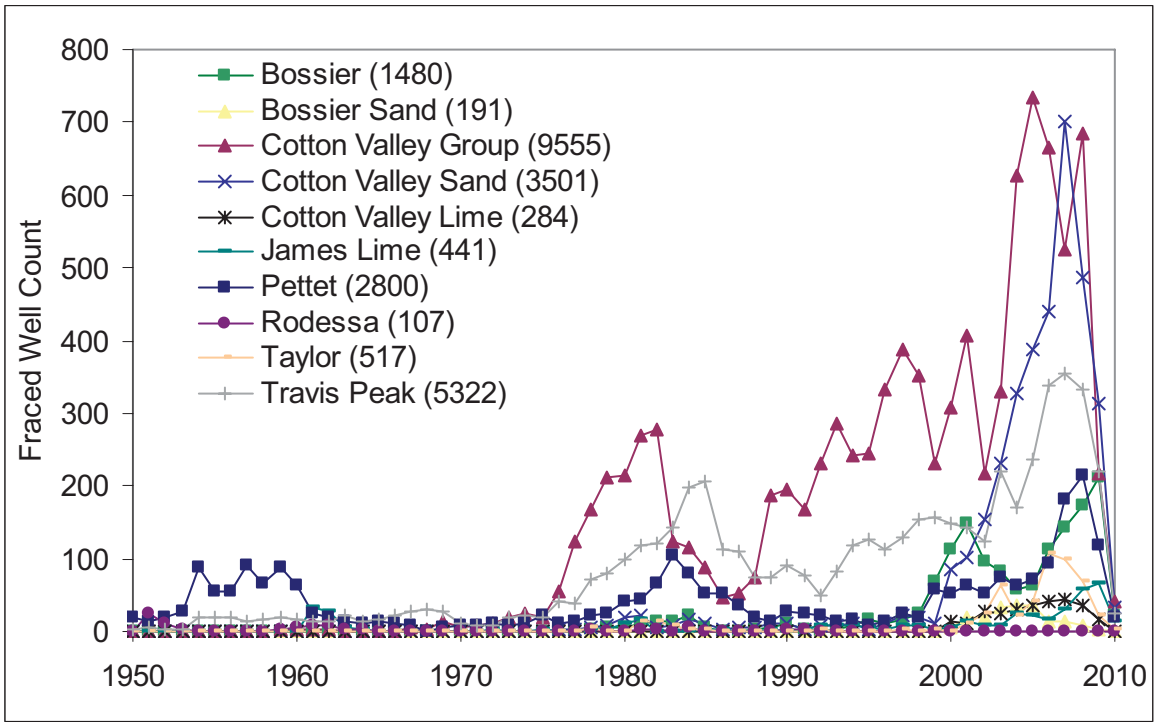
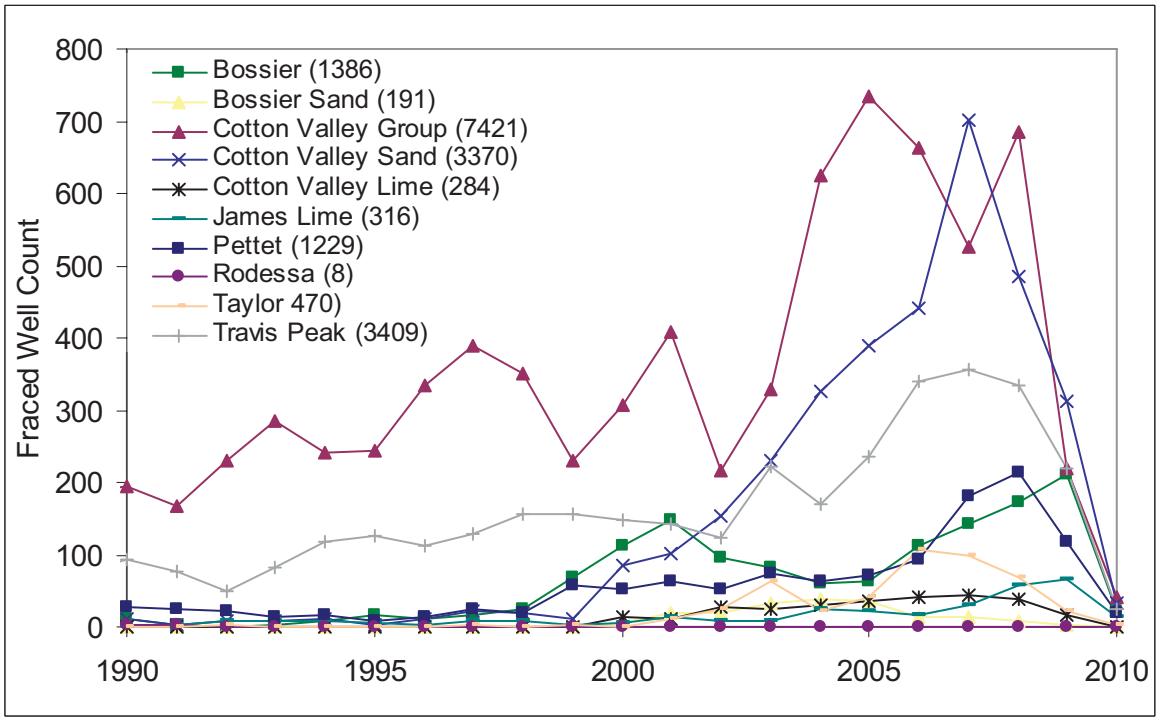


Figure 59. East Texas Basin—vertical vs. horizontal wells through time



(a)



(b)

Figure 60. East Texas Basin—Fraced well count per formation from 1950 (a) and 1990 (b)

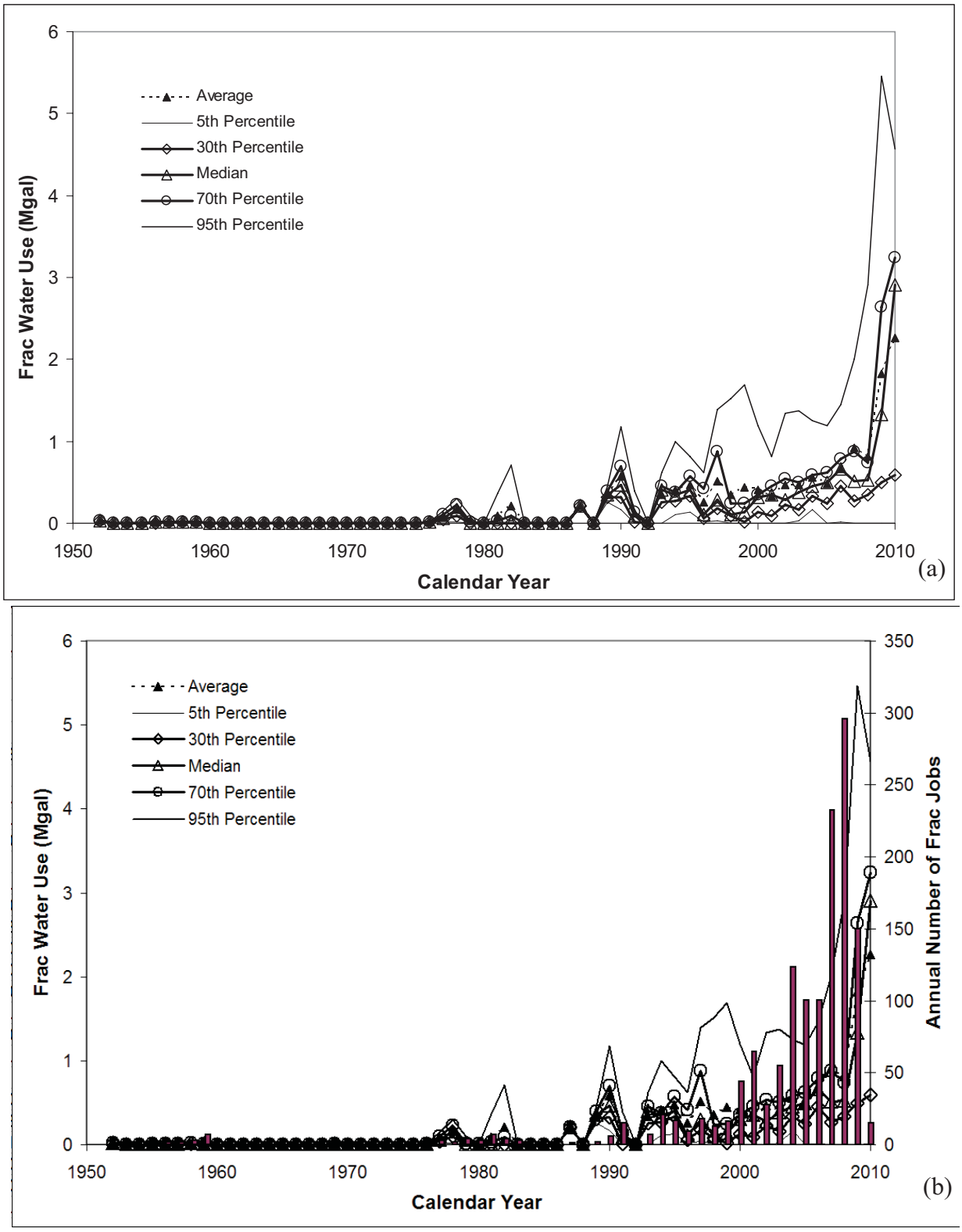


Figure 61. East Texas Basin—annual number of frac jobs (b and d) superimposed on annual average, median, and other percentiles of individual well frac water use (a and c) for 1950–~2008 (a and b) and 1990–~2008 (c and d) periods

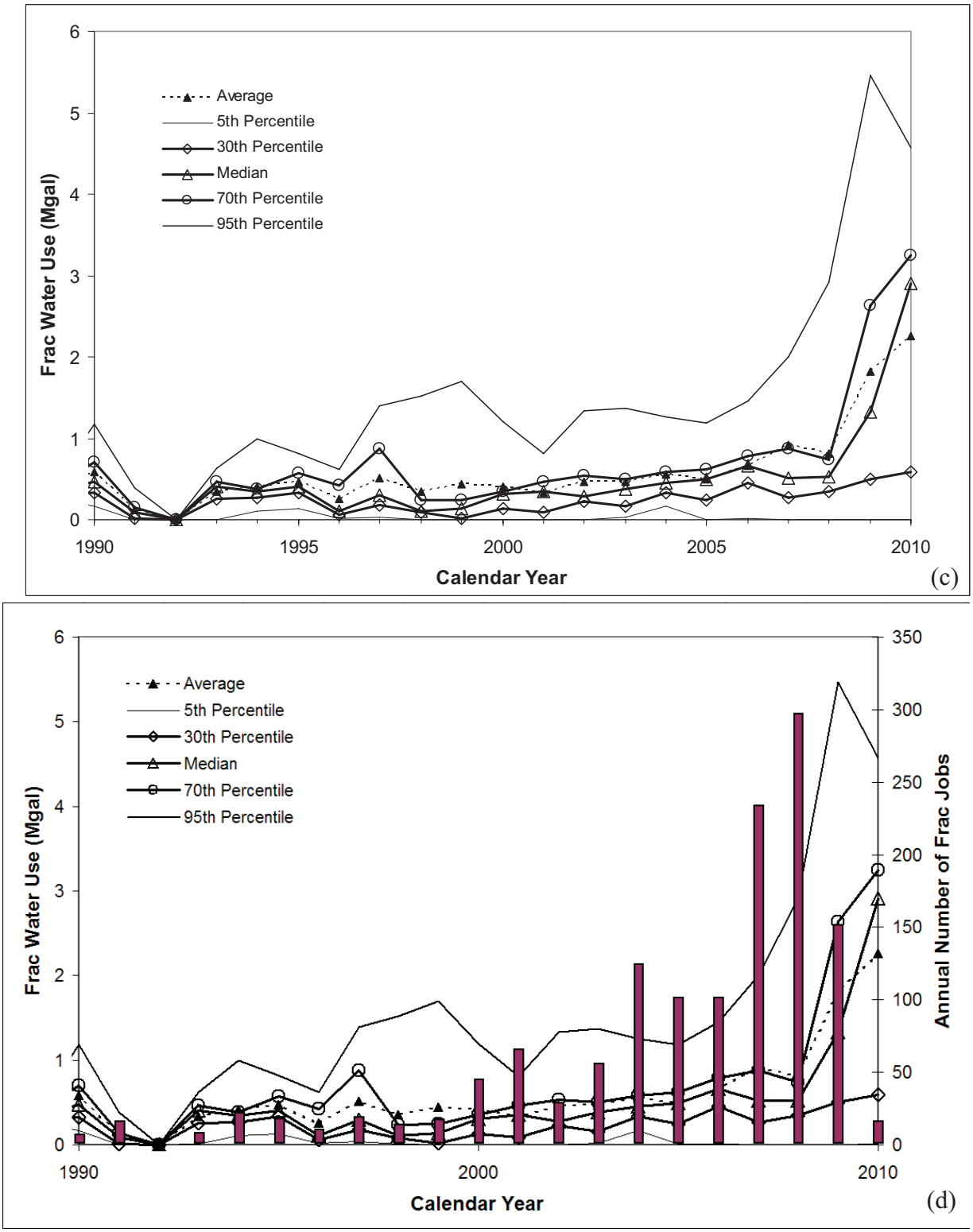
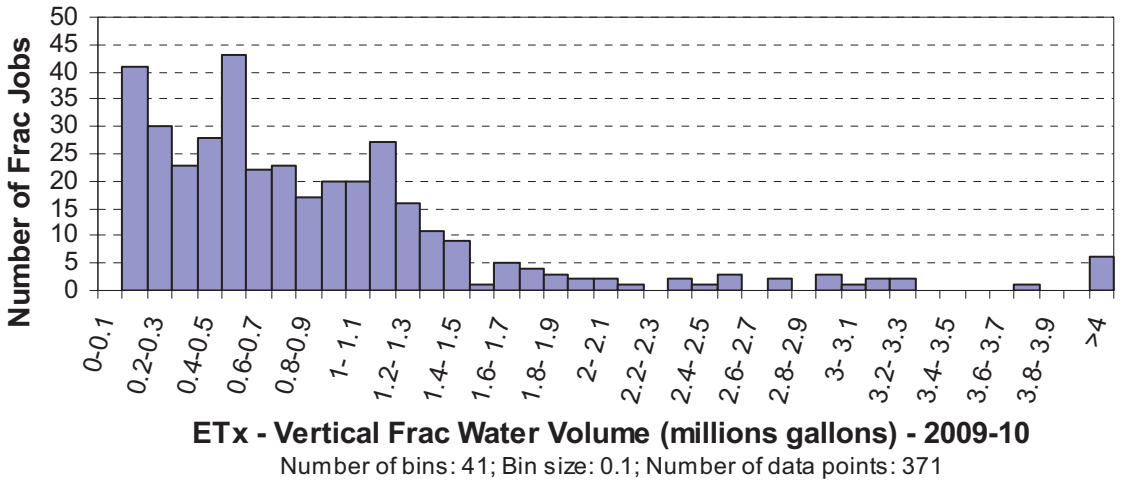
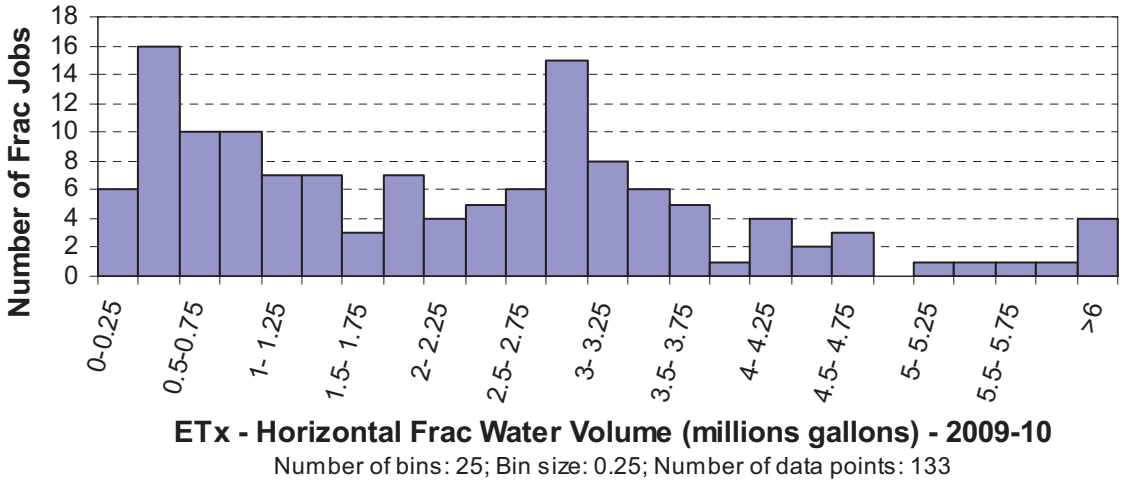


Figure 61. East Texas Basin—annual number of frac jobs (b and d) superimposed on annual average, median, and other percentiles of individual well frac water use (a and c) for 1950–~2008 (a and b) and 1990–~2008 (c and d) periods (continued).



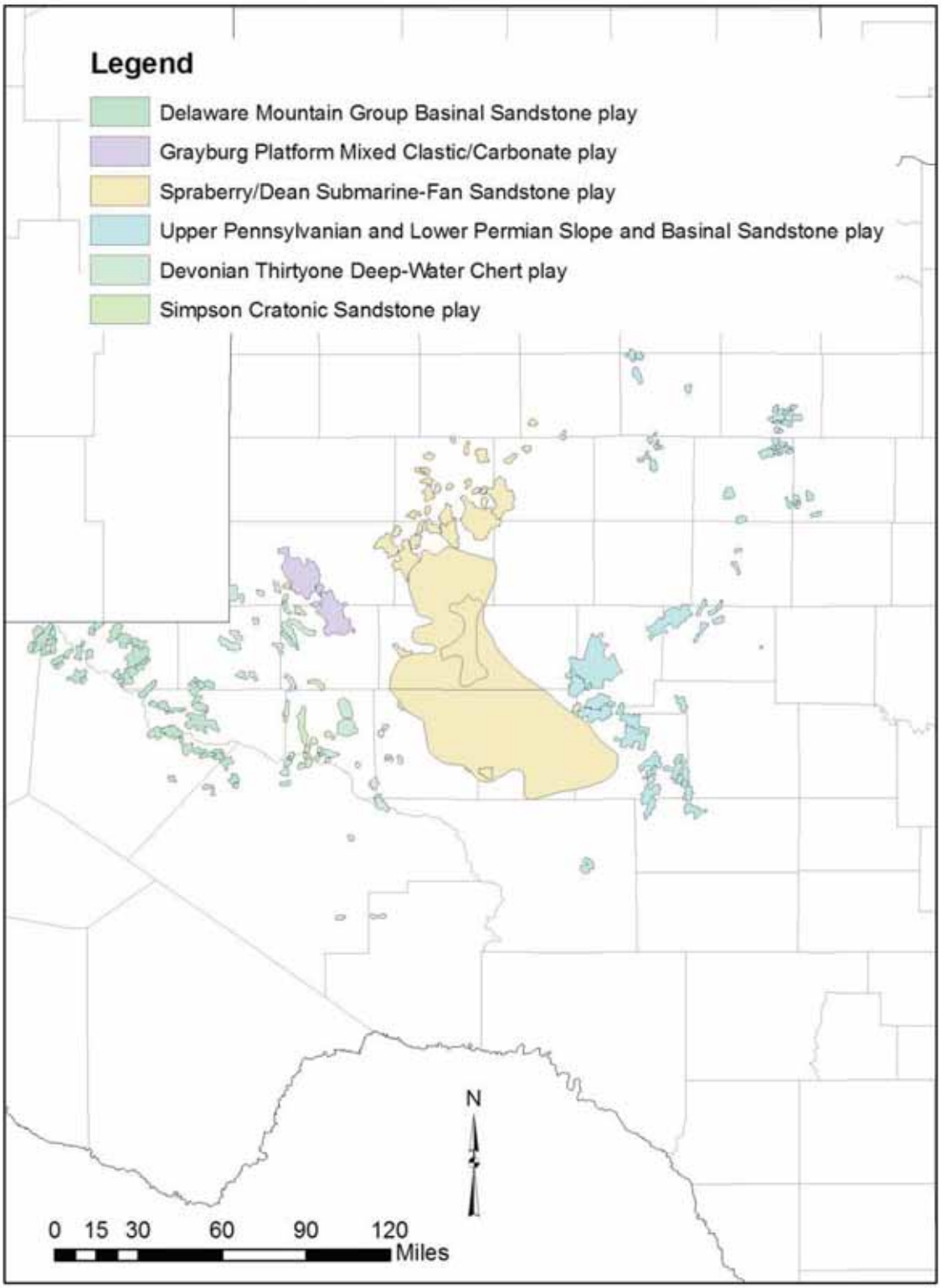
(a)



(b)

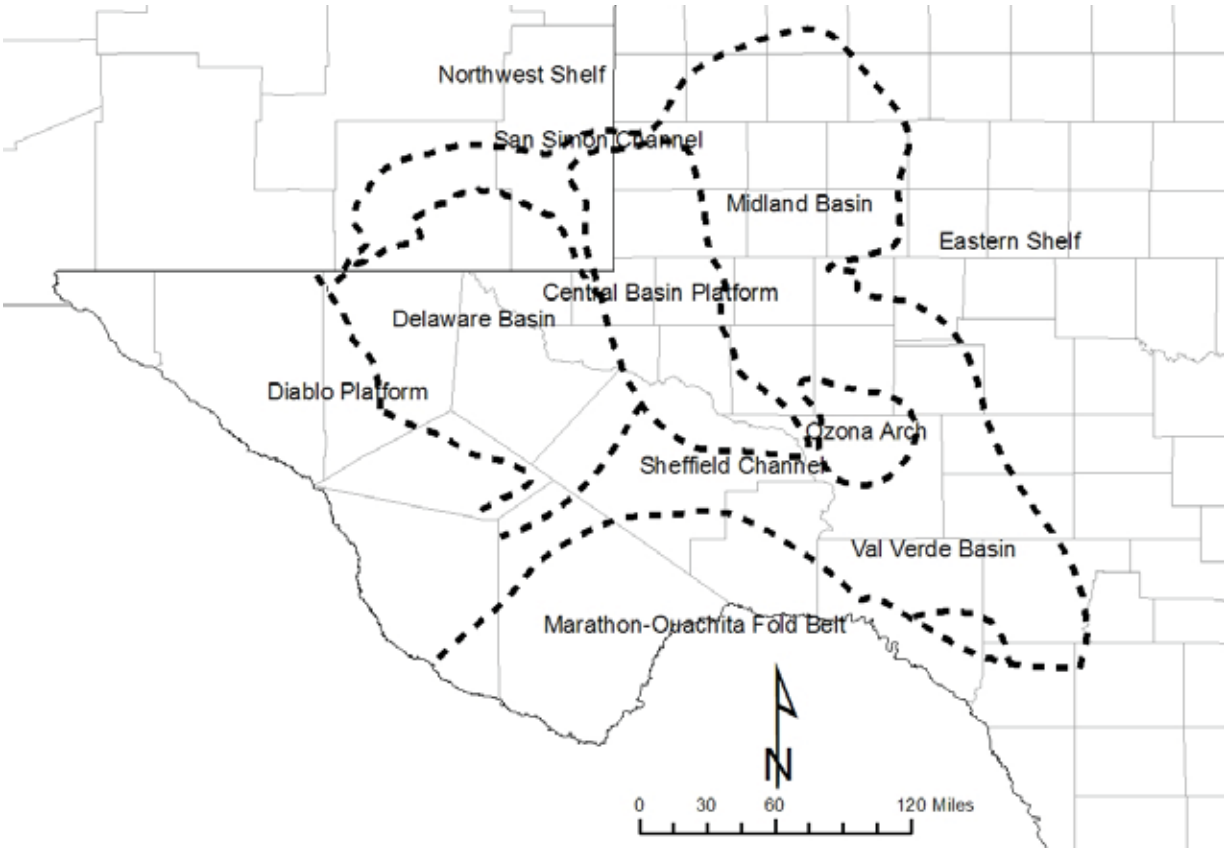
Note: Histograms include only those documented frac jobs using >0.1 Mgal

Figure 62. East Texas Basin—frac water use in vertical wells (a) and horizontal wells (b)



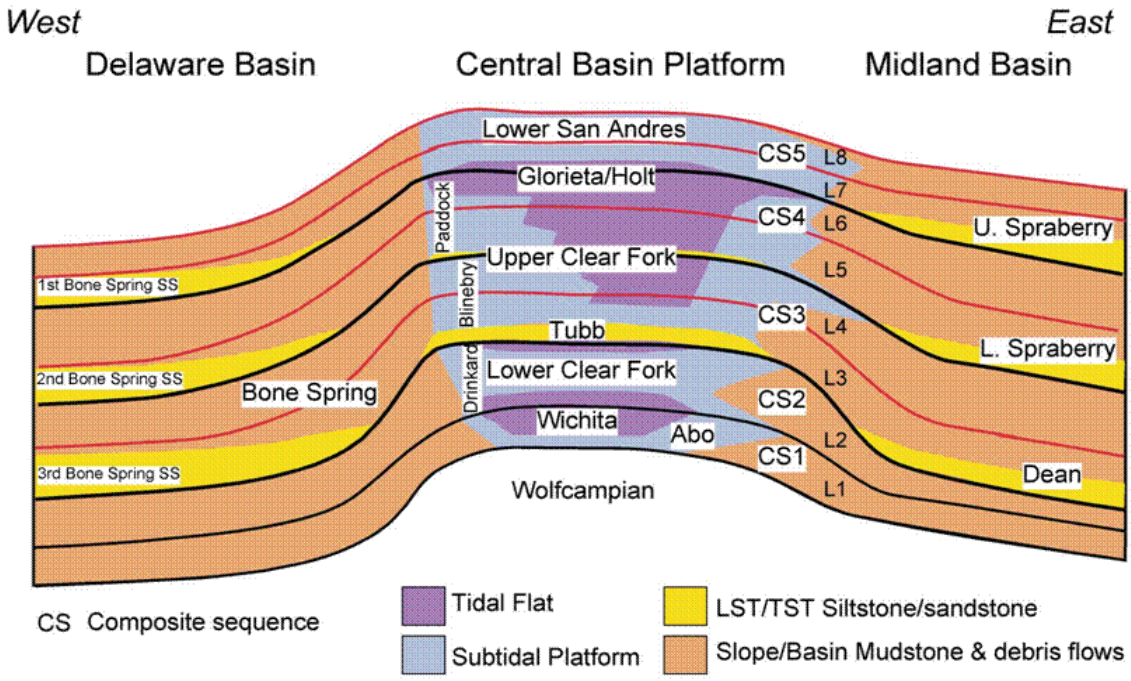
Source: Dutton et al. (2005a—GIS files)

Figure 63. Main clastic plays in the Permian Basin



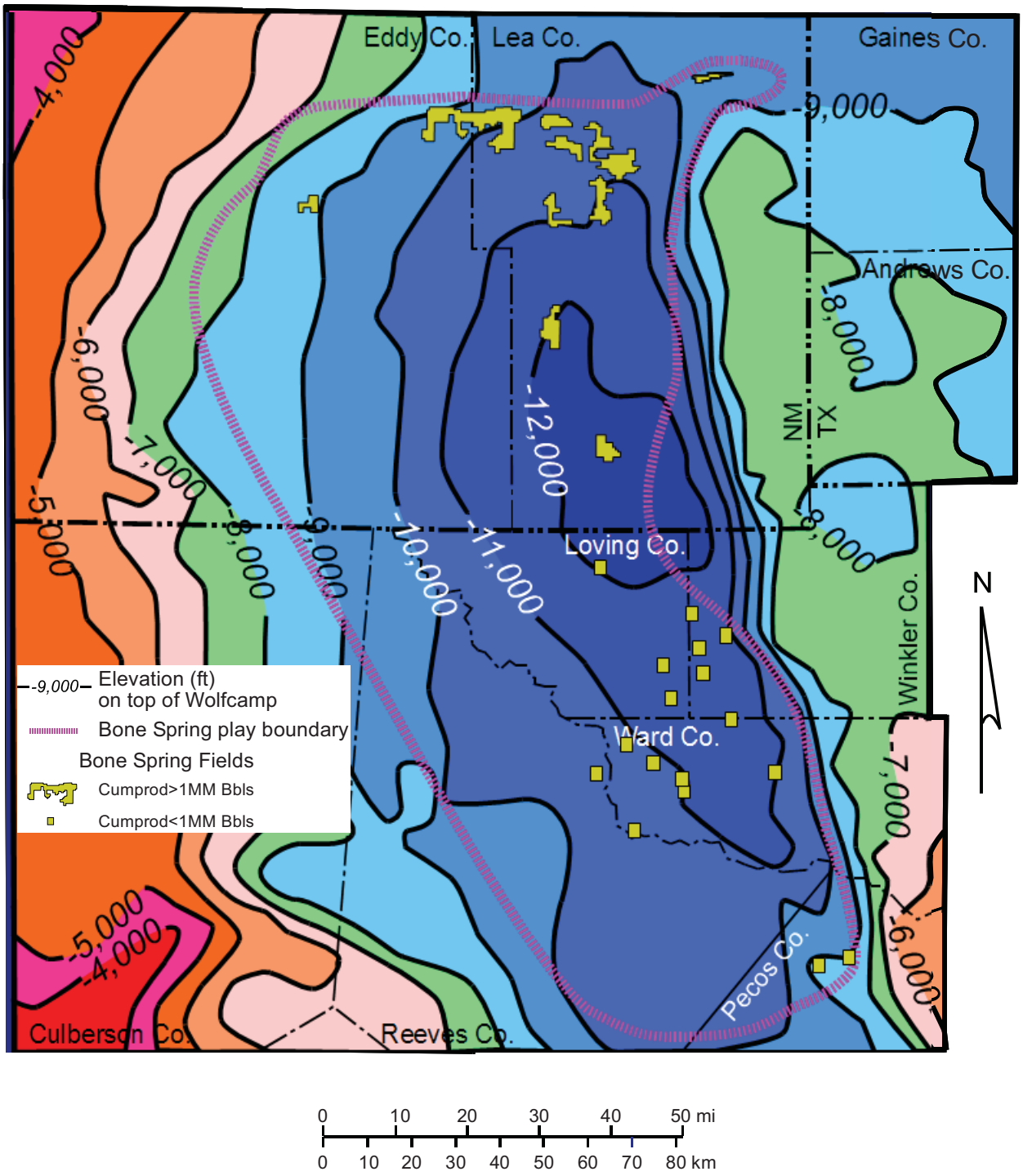
Source: from GIS coverage of companion CD of Dutton et al. (2005a)

Figure 64. Permian Basin geologic features



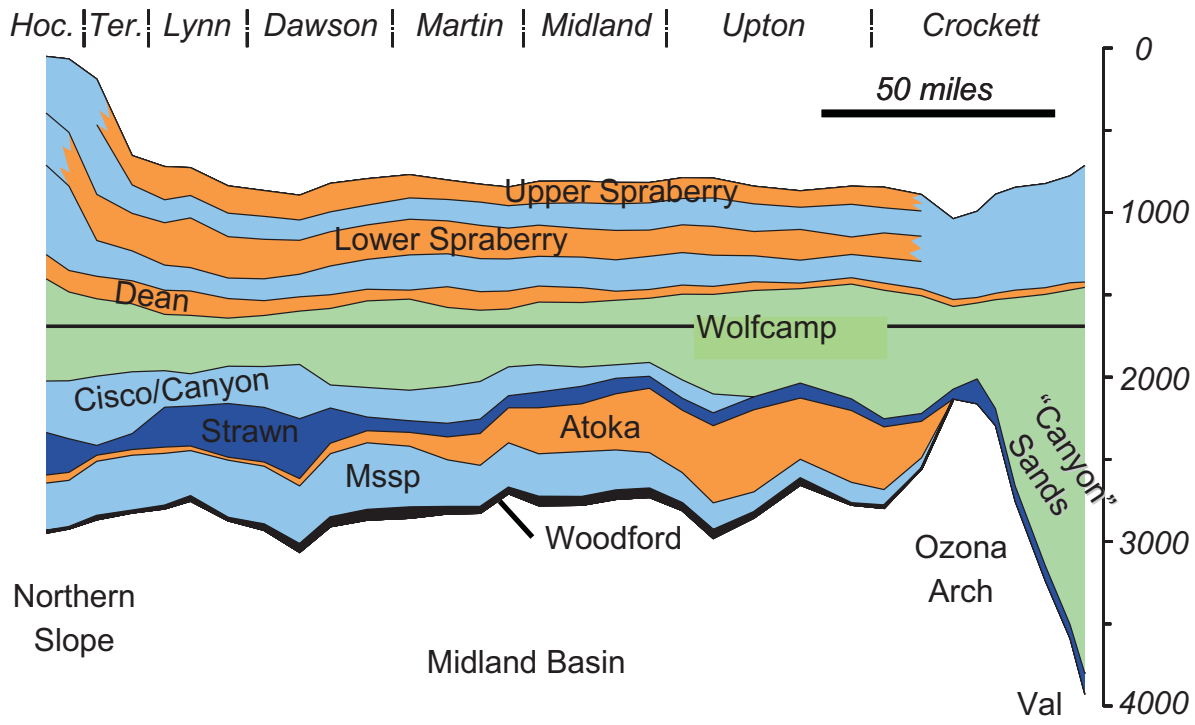
Source: Courtesy of Stephen Ruppel and Mudrock group at BEG

Figure 65. Regional sequence stratigraphy of the Leonardian (Permian)



Source: Seay Nance and the Mudrock Group at BEG

Figure 66. Bone Spring footprint and elevation of top of Wolfcamp



Source: Scott Hamlin and the Mudrock Group at BEG; vertical scale in feet

Figure 67. North-south Midland Basin cross section of Permian (Leonard and Wolfcamp), Pennsylvanian, Mississippian, and Devonian

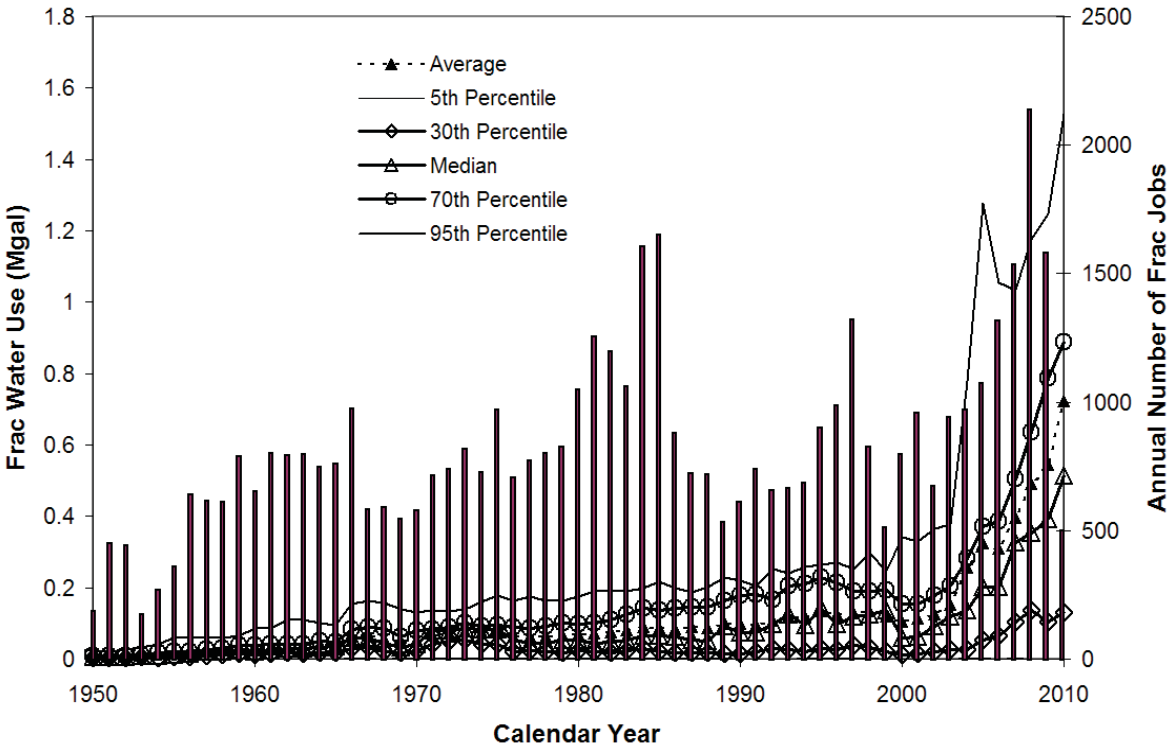


Figure 68. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (all 50,000+ wells).

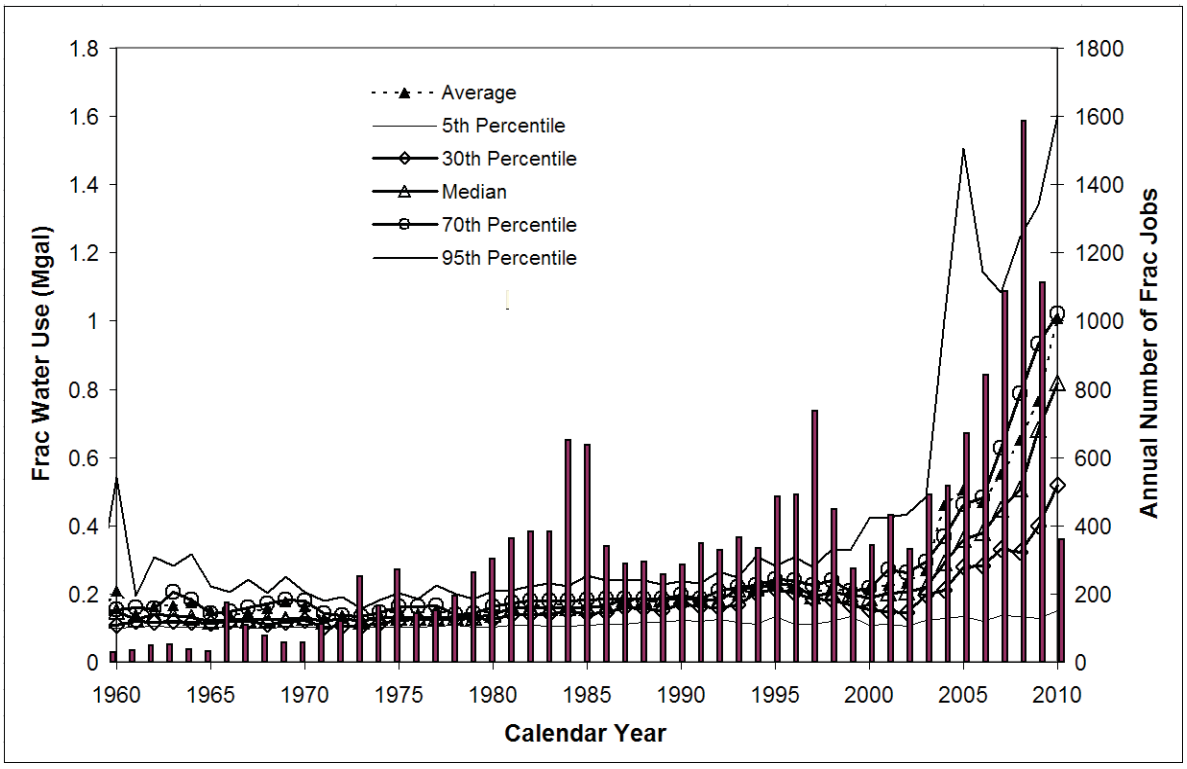


Figure 69. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (water use > 0.1 Mgal)

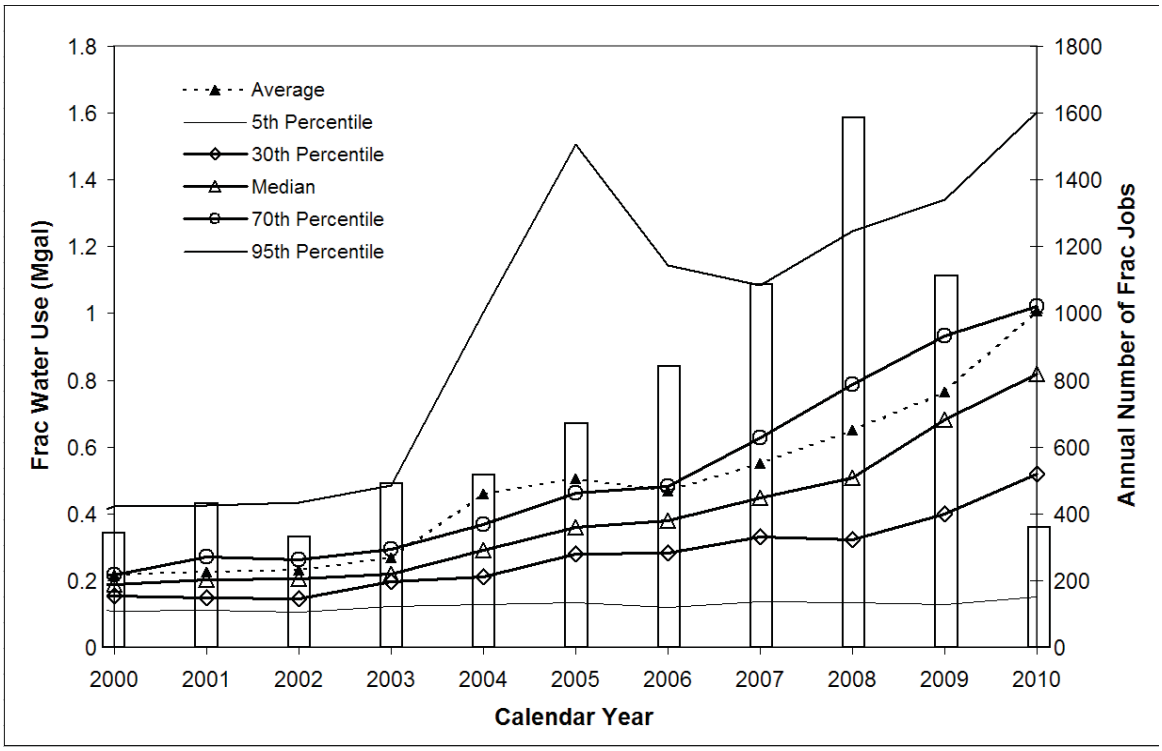


Figure 70. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (water use >0.1 Mgal since 2000)

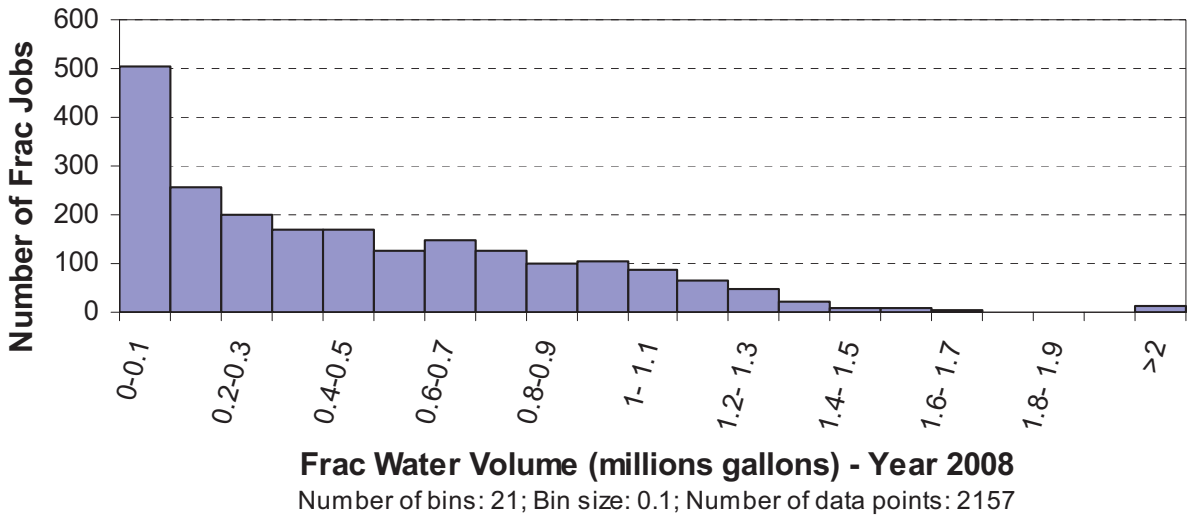


Figure 71. Permian Basin—frac water use in vertical wells

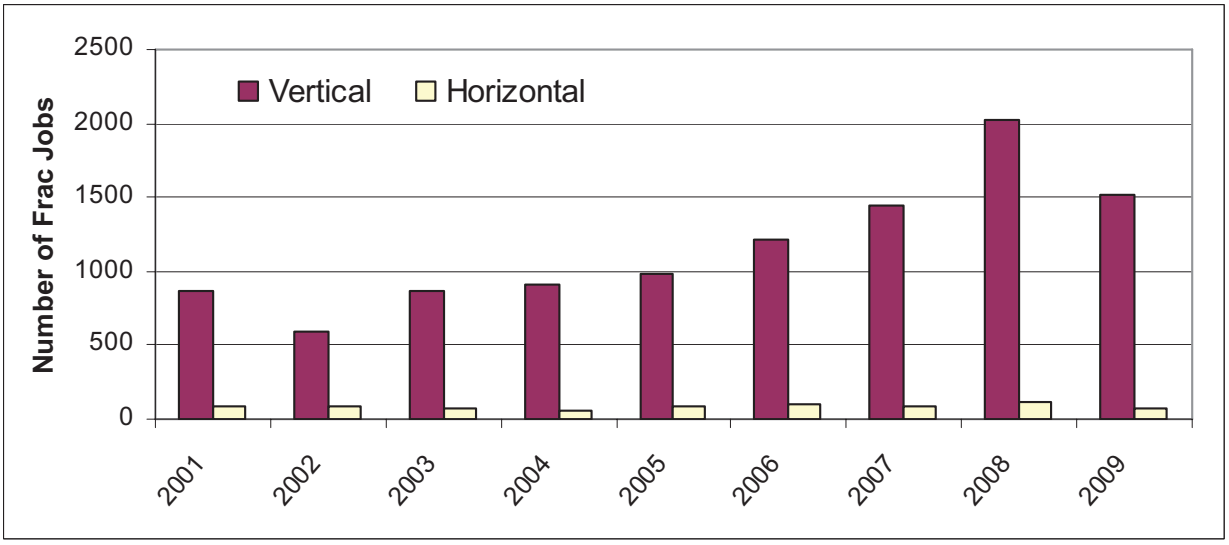
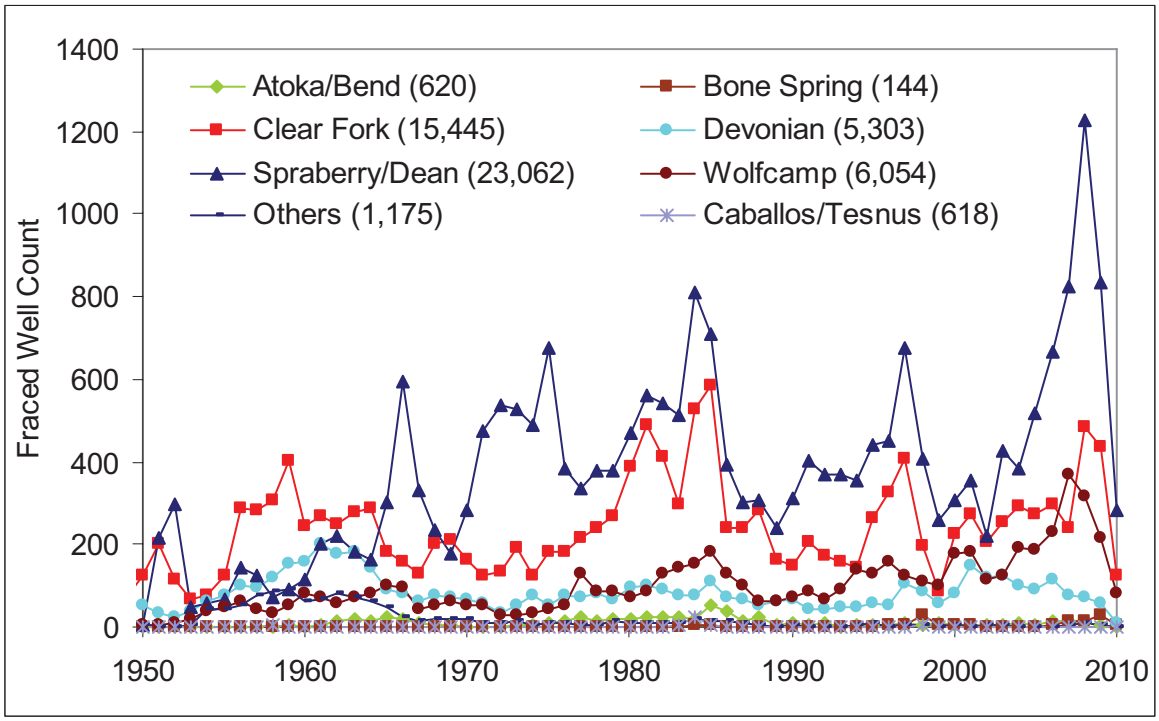
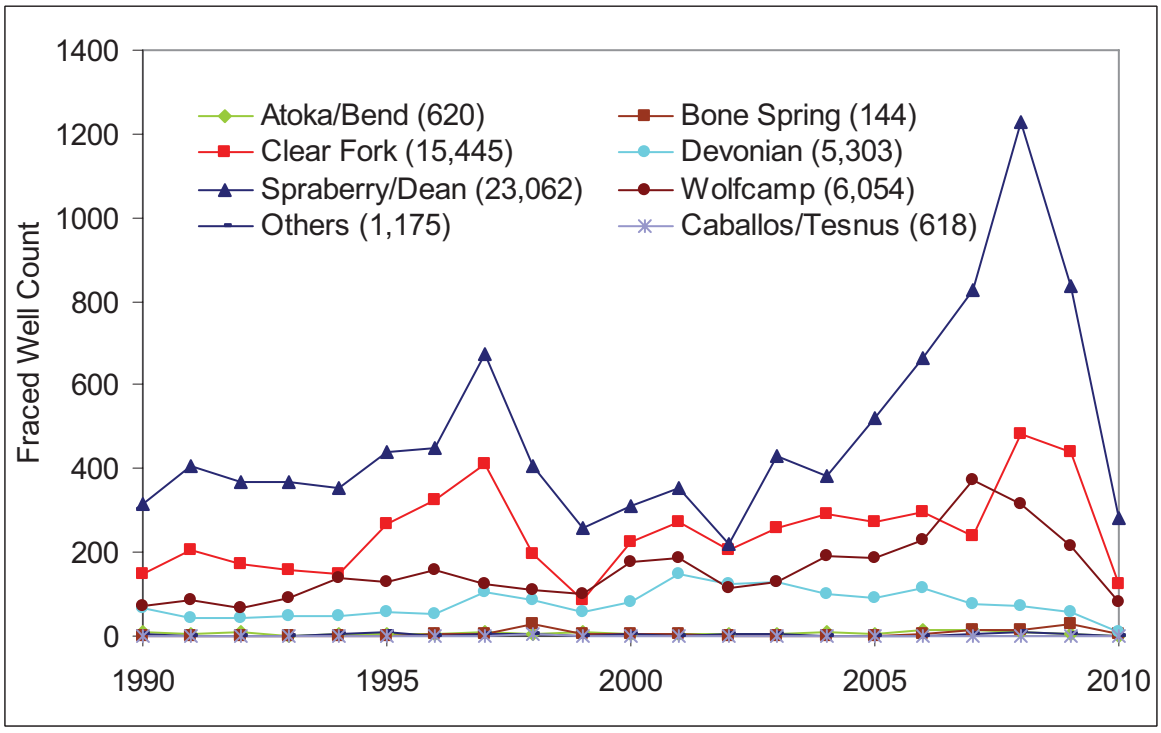


Figure 72. Permian Basin—vertical vs. horizontal wells through time

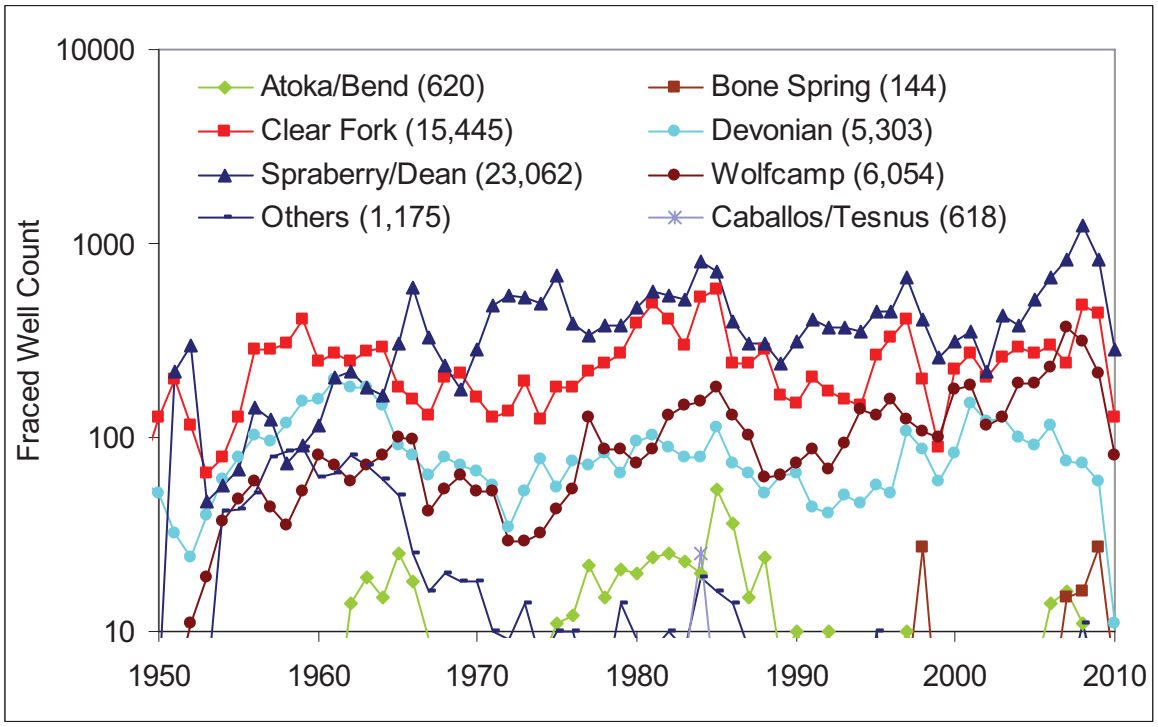


(a)

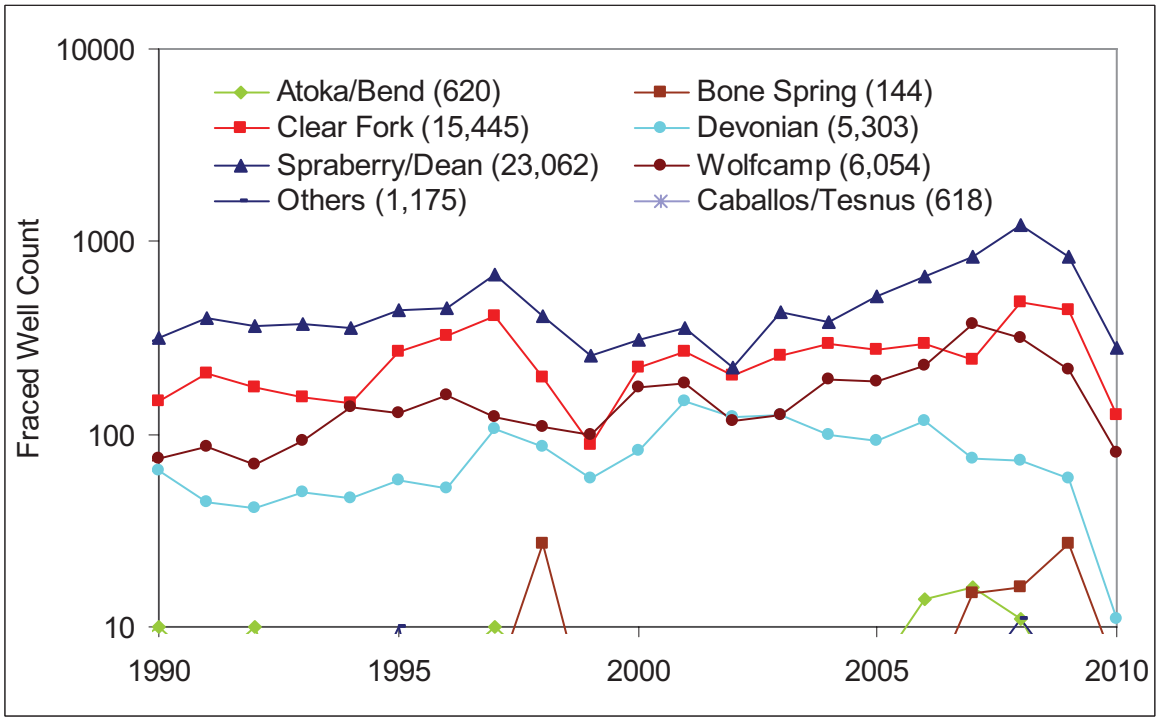


(b)

Figure 73. Permian Basin—fraced well count per formation from 1950 (a) and from 1990 (b) (linear scale—including Caballos/Tesnus)



(a)



(b)

Figure 74. Permian Basin—fraced well count per formation from 1950 (a) and 1990 (b) (log scale—including Caballos/Tesnus)

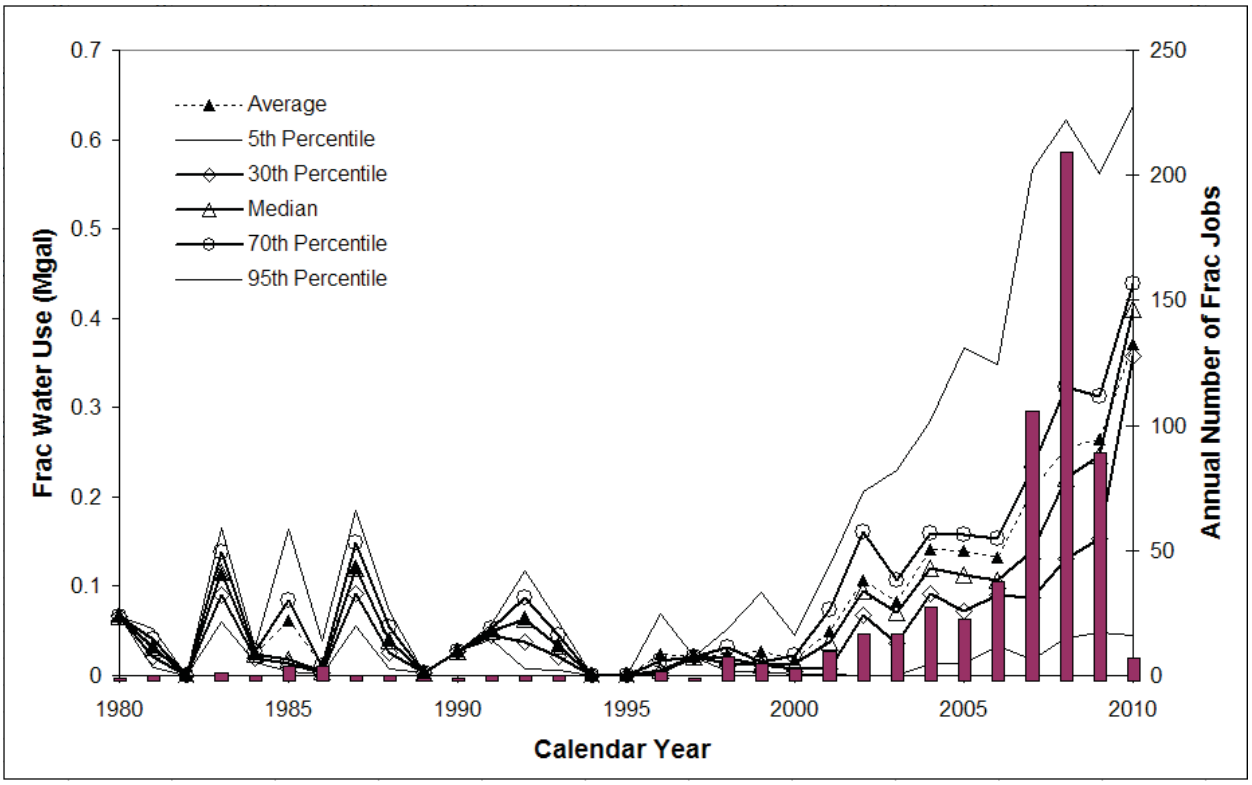


Figure 75. Caballos-Tesnus—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

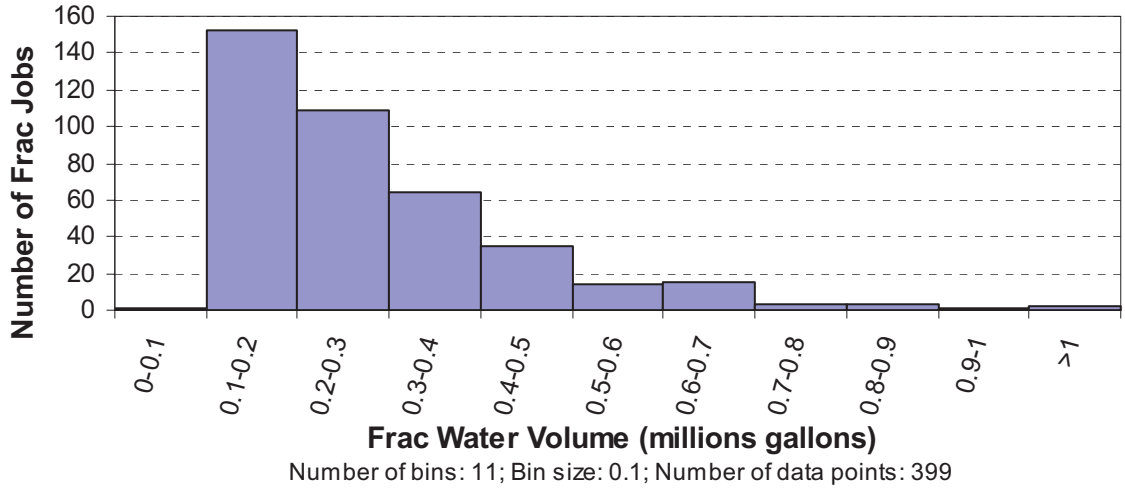


Figure 76. Caballos-Tesnus—frac water volume

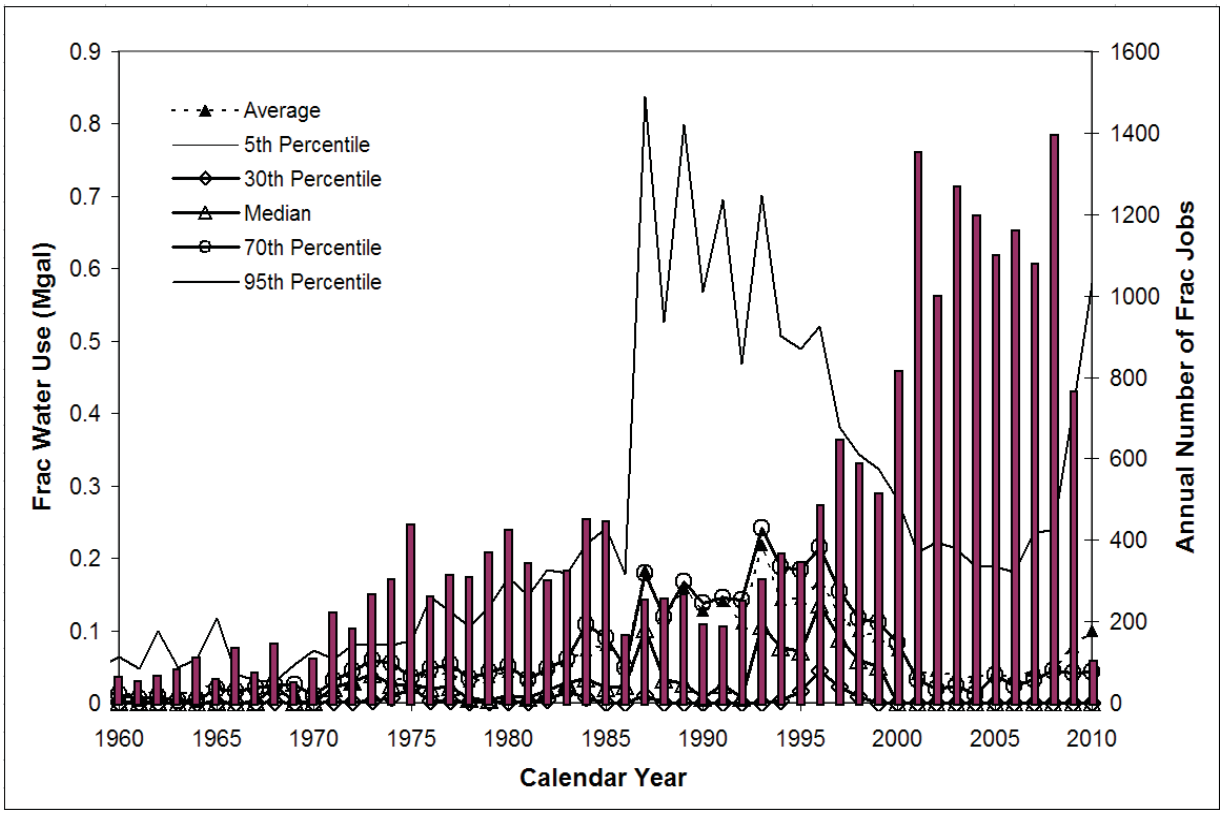


Figure 77. Gulf Coast Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

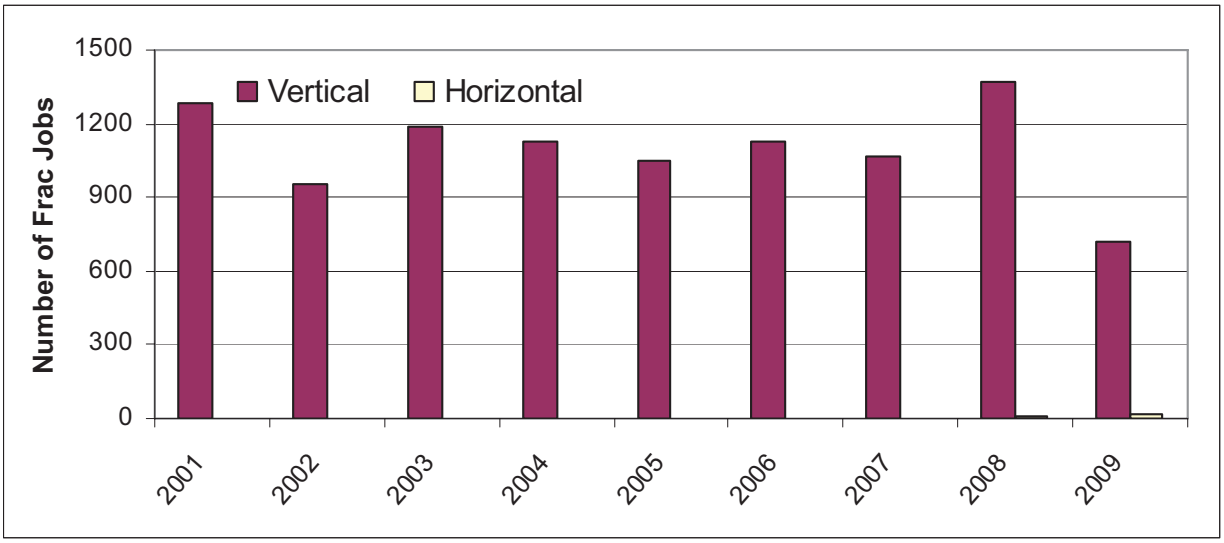
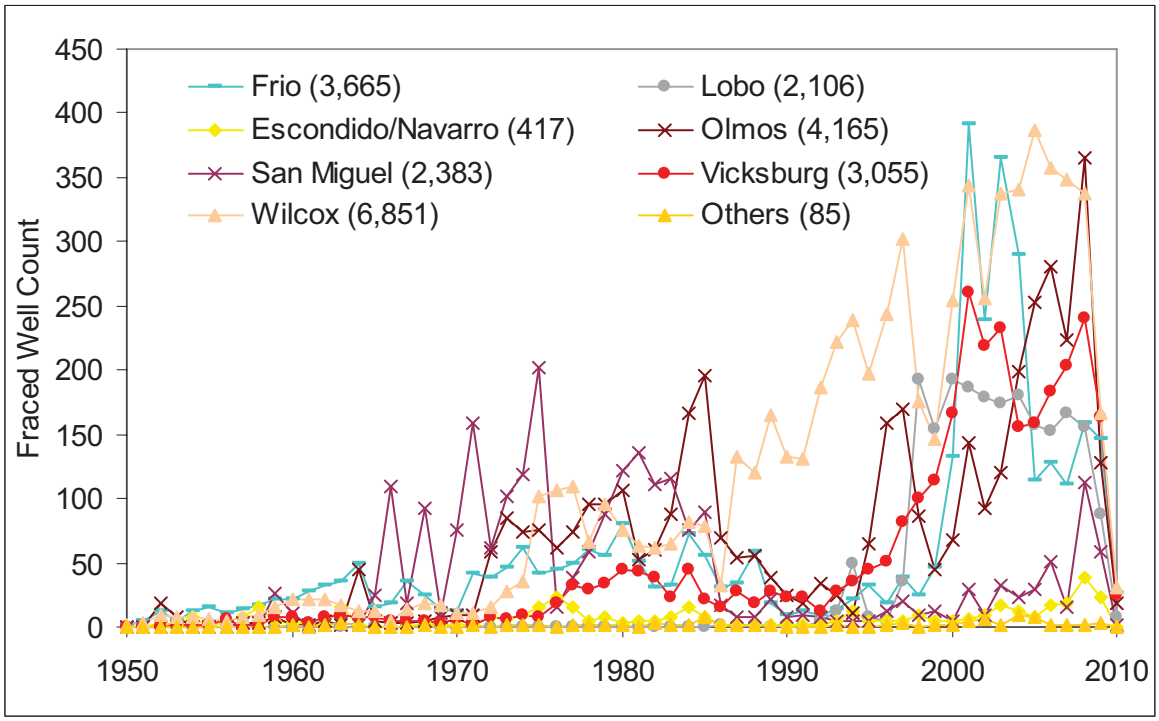
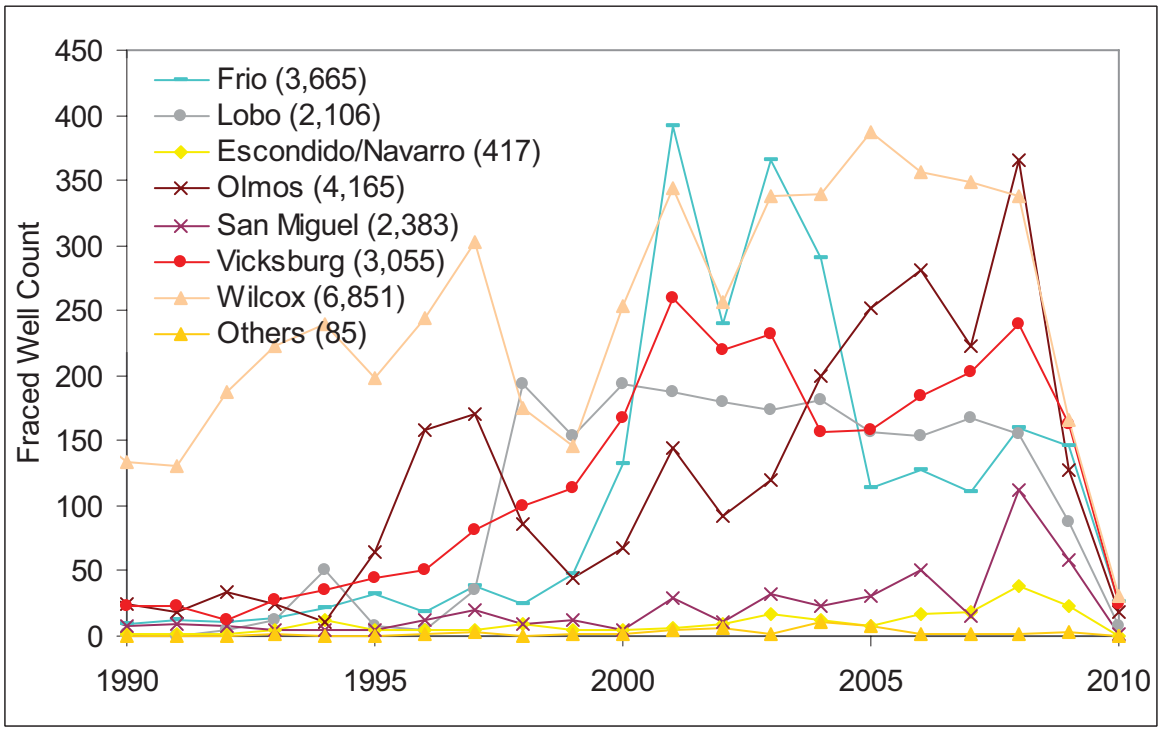


Figure 78. Gulf Coast Basin—vertical vs. horizontal wells through time



(a)



(b)

Figure 79. Gulf Coast Basin—fraced well count per formation from 1950 (a) and 1990 (b)

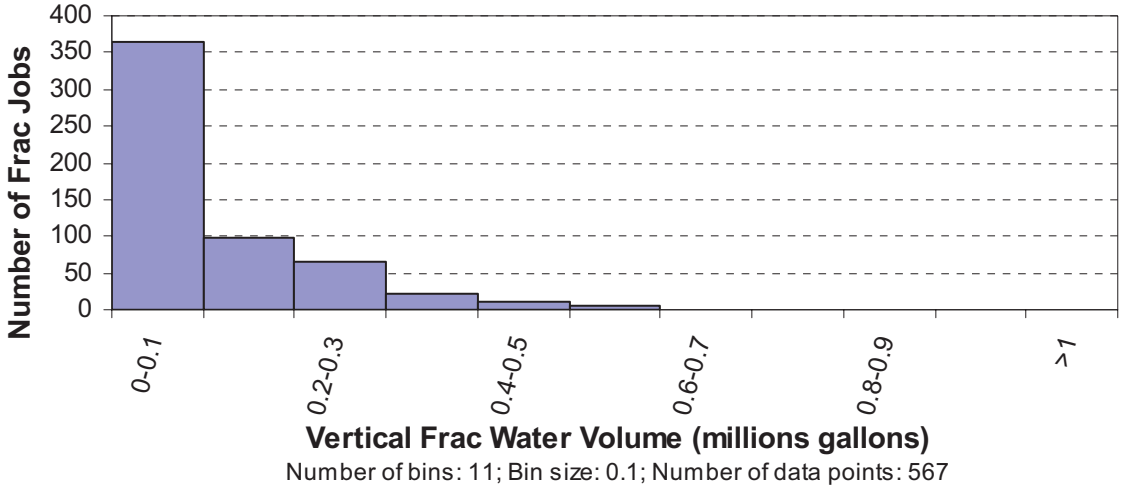


Figure 80. Gulf Coast—frac water volume (2008)

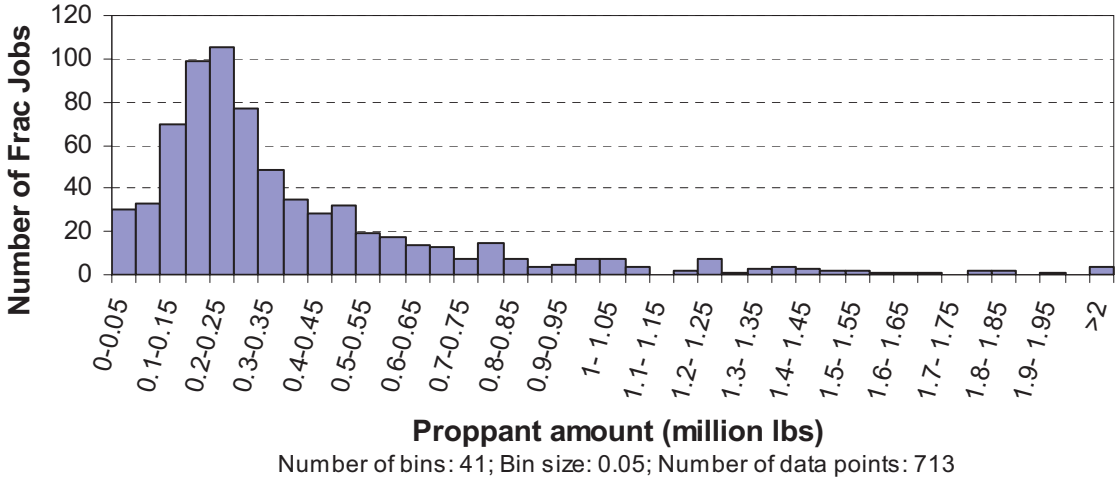


Figure 81. Gulf Coast—proppant volume (2008)

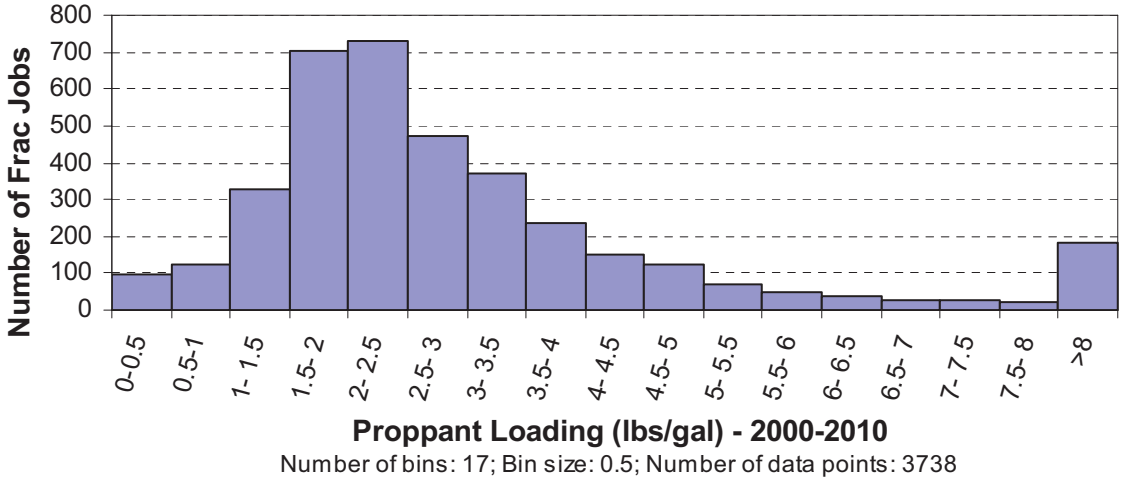


Figure 82. Gulf Coast—proppant loading (all years)

4.2 Oil and Gas Drilling and Waterflooding

Besides stimulation, the oil and gas upstream industry makes use of fresh water during waterflooding operations and the drilling of wells. The amounts used are uncertain because they are not clearly documented in regulatory forms. In Texas, there is no requirement to document exactly the type of fluids injected in UIC Class II wells (such as those wells used for waterflooding); only the overall total volume and the types of fluids (by "checking a box" in the mandatory H10 form) need be documented, without specifying their share. A cursory calculation also shows that the amount of water used to develop drilling muds for the 10 to 20,000 wells drilled each year in the state could significantly contribute to total fresh water use in the mining category. U.S. DOE (2009, p. 64) put forward a figure of 400,000 and 1,000,000 gal to drill a well in the Barnett and Haynesville Shales, respectively. Volumes undoubtedly vary substantially between wells, and those horizontal wells with long laterals represent the high end of the range. Still, these values are significant and could have a large impact on overall mining water use if all the water is fresh and if the rate per well is sustained at the state level.

4.2.1 Waterflooding

4.2.1.1 Information available before this study

A look at historical reports suggests that the amount of fresh water used in the oil and gas industry has been decreasing during the past few decades. Guyton (1965, p. 40) estimated that in Texas (mostly Permian Basin) and southeast New Mexico, the industry used approximately 50 to 70 thousand AF/yr of fresh water in the early 1960s for the extraction process. In the middle of the 20th century, the RRC used to publish biennial reports on secondary and tertiary recovery, including water use. The latest of such reports seems to have been published in 1982 (RRC, 1982). Fresh-water use was reported at ~80 thousand AF in 1980 and 1981 (Table 15). The latest comprehensive survey of fresh-water use in the oil and gas industry dates back to the 1990s (De Leon, 1996), and fresh water use was estimated at ~30 thousand AF. The survey concerned mostly pressure maintenance, waterflooding, and other EOR techniques, but not drilling. We summarize next the content of the letter report. In 1996, the RRC sent a survey request of fresh and brackish water usage in EOR projects in 1995 to oil and gas operators. The survey was initiated in November 1996 using a special makeup water-survey form (Form H-17). A total of 1,543 forms were mailed, with a return rate of ~84%. Whether the results were scaled to account for unresponsive operators is unclear, but they probably were not. The forms documented the injection of 251,716,698 bbl (32.444 thousand AF) of fresh water during calendar year 1995. Definition of fresh water is more lax than for the rest of this document because it includes all water with a TDS <3,000 mg/L. The volume of fresh water actually injected was only 7.6% of the total fresh water volume permitted for injection in 1995 (3.3 Bbbl). The volume of fresh water actually injected represents 3.3% of the total combined volume of all liquids (7.63 Bbbl) injected ca. 1995. The forms also documented the injection of 78,180,043 bbl (10.077 thousand AF) of brackish water during the same period. Brackish water in this RRC survey is defined as having a TDS between 3,000 and 10,000 mg/L. Brackish-water use represents about (24%) of the combined non-saline water. The top five counties (Gaines, Stephens, Hockley, Yoakum, and Andrews) represent 76% of the total fresh-water consumption, and adding five more (Cochran, Lubbock, Dawson, Garza, and Leon) represents 88% of the total (Table 16 and Figure 83). De Leon (1996) did not document the breakdown of brackish-water use by district or county. All of the top 10 counties belong to the Permian Basin except the last one (Leon County). A total of 55 counties were reported by operators to receive fresh-water injection. Many others in the list are

also located in West Texas (Figure 83); RRC districts 8A+8 (~Permian Basin) correspond to 69.4% of total fresh-water injection, and adding district 7B (>99% in Stephens County) increases the share to 92.0%. Adding district 7C instead of district 7B results in 69.7% of total fresh-water injection; a combination of districts 7C, 8, and 8A corresponds to a common definition of the Permian Basin using RRC districts. The large amount of water reported to have been used in 1995 in Stephens County is anomalous, both in terms of its location and of its high county-level water-use coefficient (that is, water amount used in the county divided by county production) (Figure 84) and is investigated later because it makes up >20% of the total fresh water used in 1995 in Texas oil fields. Recomputing the water-use coefficients by including production only from those fields being flooded (list provided in De Leon, 1996) still shows a high coefficient but within the tail of the distribution (Figure 85). Most of the fields are in the 2- to 7-bbl range of water/bbl of oil, although Stephens County regular fields display a water-use coefficient three times higher. Something like this could have happened if a large EOR operation had started around that time, but a look at the production of these combined fields does not show an uptick in production in 1995 (at ~3.7 million barrels) or shortly thereafter, but, instead, a slow decrease until 2002, at which time production stabilized at ~2 million bbl/yr. However, publications by Weiss (1992) and Weiss and Baldwin (1985) suggest that major EOR operations were ongoing at the time in Stephens County.

Approximately ¾ of the fresh water used in 1995 is groundwater, most of it from the Ogallala aquifer (~85% or ~60% of total injected fresh water). However, note that 1995 received less than average precipitation (NOAA historical climatological data and records for Midland) and that groundwater use in that year might have been anomalously high. Another important note concerns double-counting: in 1995 >40% of the fresh water was purchased. Anecdotal evidence suggests that water purchase is still current practice. There is no issue if the water was purchased from wholesalers, but if it was purchased from municipalities, then it may already have been counted toward municipal use.

Total water use of fresh and brackish water in the oil and gas industry amounted to 330 million barrels (42.5 thousand AF) in 1995. RCC (http://www.rrc.state.tx.us/barnettshale/wateruse.php) projected that it would have decreased to 316, 276, 254, and 212 million barrels (40.7, 35.6, 32.7, and 27.3 thousand AF) in 1998, 1999, 2000, and 2001, respectively. Note that these figures were extrapolated before shale-gas growth but may include reporting from tight-gas water use, particularly in East Texas. The basis for these figures is not explained in the RRC documents.

4.2.1.2 Extrapolations from the RRC 1995 Survey

Early studies suggest that most waterfloods take place in West Texas (RRC Districts 8, 8A, and 7C; see Figure 9 for location). In addition, most of the oil produced in the state comes from the Permian Basin (Figure 86 and Figure 87). Only oil reservoirs are typically waterflooded. A look at the number of wells permitted to inject fresh water (Table 17) confirms that Districts 8 and 8A are the center of this practice. This section focuses on these districts. Given the current lack of specific reporting of fresh- and saline-water volumes, our approach is to relate known volumes of oil produced in 1995 with known waterflood water volumes. The 1995 RRC survey is the most recent comprehensive survey to be completed on waterflood water use and was used as a basis for estimating current water use. The RRC survey was combined with another survey performed for this study (Galusky, 2010).

One way to compute future water use is to tie oil production and water use, which can be done at the county level and which is the elemental unit of this study (Figure 84), or at the finer field

level (Figure 85). The first step is to analyze 1995 production data vs. RRC survey fresh/brackish-water use (De Leon, 1996). Production numbers were extracted from the RRC online query engine for the calendar year 1995. At the coarsest state level, Texas produced 1134 million barrels in 1995, resulting in an average water use of 0.22 bbl/bbl. If one considers only those counties that reported fresh-water use, the average climbs to 0.79 bbl/bbl for oil production of 319 million barrels. Average water use can be low in some counties (<1 bbl/bbl) because many fields may not undergo secondary or tertiary recovery, but in those counties regularly performing waterfloods, a reasonable average is between 1 and 2.5 bbl/bbl. Field scale seems the most appropriate scale for understanding water use, but even then figures depend on the stage of the waterflood and on the fraction of those production wells not yet impacted by the flood. However, given the relatively large number of fields considered (~100), we expect the data to be representative of waterflood water use in 1995. The "Stephen County Regular" oil field has an anomalously high water use, accounting for ~20+% of total 1995 fresh-water use. Overall fresh-water consumption obtained by summing up all field oil production and water use and taking the ratio is 2.28 bbl/bbl, which is equivalent to making the average per field weighted by the field production. Taking the average, giving the same weight to all fields, results in a value of 5.67 bbl of fresh water/bbl of oil. Somewhat arbitrarily dismissing outlier fields with an average >15 or <1 bbl/bbl results in an average of 4.5 bbl of makeup fresh water/bbl of oil.

A piece of information more readily available than fresh-water injection is total injected fluid volume (made available in RRC records as disposal in producing formations, disposal in nonproducing formations, and waterfloods and other secondary and tertiary recovery processes). Thus, in order to make fresh-water-use projections, we need an estimate of the share of fresh water relative to all water being injected for waterflood secondary-recovery processes. Unfortunately, the RRC website does not currently include injection volumes for 1995, the reference year for fresh-water injection, and we were not able to access the information. It does, however, contain injection volume at the district level for 1998 through 2002 (Table 18, Table 19, and Figure 88). The website (http://www.rrc.state.tx.us/data/wells/statewidewells.php) breaks down water as injected into disposal wells (either in the producing formation or not) or for recovery. Here we are only interested in water used for waterflooding and other recovery processes that represents ~58% of total injection in this year range. Although variable across the years, a representative number is 3.5 million barrels, ~75% of which is injected in districts 08 and 8A in the Permian Basin, and ~90% if districts 7B and 09 are also included. In these four districts, making up almost of the water used for secondary and tertiary recovery, most of the water is used for secondary recovery (>75%) and not disposed of (Figure 89). Percentage of fresh water in the total volume of water used in waterflood varies (Table 20). Contrasting reported waterflood volume (all water types) during the 1998–2002 period to reported fresh water used in 1995 suggests that, at least 10 to 15 years ago, at most 4% of waterflood water was fresh (later we will add correction factors). District 7C is anomalously high at ~14%; a likely reason is that there is less produced water available near the waterflooded field and the proximity of Possum Kingdom Lake in Stephens and neighboring counties. District 8A, with more than half of the state volume of waterflood fresh water, shows a percentage close to 10% fresh-water use, and close to 13% if brackish water is added.

Closer to 2008, after a lack of data for a few years (2003–2006), the RRC website provides data from 2007 through an interactive query site compiled from H10 forms (http://webapps.rrc.state.tx.us/H10/h10PublicMain.do). However, unlike the 1998–2002 period, there is no breakdown in water type. A plot of injection volumes collecting 1998–2002 and

2007–2008 data sets (Figure 91) shows no major change in the injection volume pattern. A simple extrapolation, assuming that waterflood/total injection and fresh-water waterflood ratios have not changed in the past 15 years and using total injection figures from 2007 and 2008, results in total waterflood water use of ~28 thousand AF (Table 21), most of it in district 8A. This value must be considered only preliminary because, as described in the next section, adding correction factors more than halves this initial water-use estimate.

4.2.1.3 Current Waterflooding Water Use

In this section, we integrate results from the Permian Basin operator survey (Galusky, 2010). The survey provided information (1) on added operator reliance on brackish water as opposed to fresh water, (2) on switching from disposal into nonproducing formations to useful injection into producing intervals, and (3) increased dependence on secondary and tertiary recovery, as illustrated in Figure 92, with a stable water-injection level combined with decreasing oil production. The 1995 RRC survey (De Leon, 1996) reports a fresh-water–brackish-water split of ~75%– 25%. New confidential, anecdotal information obtained through the informal survey of Permian Basin producers suggests that the 2010 fresh– brackish water split now favored brackish water –20% fresh water and 80% brackish water. In other words, the fraction of fresh water in the usable (fresh+brackish) water category went down from 75% to 20% in 15 years. In addition, although the information was gathered from Permian Basin operators, we assumed it valid across the state (error, if any, is small at the state level because most fresh water for waterflooding purposes is injected into the Permian Basin). We also assumed that, overall, increased reliance on waterfloods and other recovery processes is balanced by the increased useful use of saline water.

Note that in the following developments we discuss projections to 2060, as well as current fresh-water use. Both are calibrated in the same calculation with the help of the 1995 RRC survey. The estimation (more accurate than the preliminary estimate of the previous section) of historical and forecast water use for oil-field-pressure maintenance in EOR (waterfloods and CO_2 floods) production entailed the following steps:

a- Historical (1995–2010) annual oil production from EOR was estimated on the basis of published data and company surveys and anecdotal information (for waterflood oil production) (Figure 93).

b- Applying and generalizing basic reservoir engineering principles, we estimated that at least 1.3 bbl of water is required for EOR pressure maintenance for every barrel of oil produced.

c- The fresh-water fraction of EOR makeup water in 1995 was estimated to be ~75% of the total. The fresh-water fraction of EOR makeup water in 2010 was estimated to be 20% of the total and was taken from the returned company surveys. We assumed that there has been a linear decline in the fraction of fresh water used in EOR between these periods and that this decline will continue until it reaches a value of 5% by 2023, at which point we forecast that it will hold this percentage through 2060.

d- We estimated the fraction of oil production from EOR in 1995 to be approximately 61% of total oil production and assumed that this fraction increased linearly to a value of 66% in 1997, as estimated by RRC. We then held this rate of annual increase through the last year of the forecast period of 2060. Anecdotal evidence (for example, Henkhaus, 2007) suggests that about ⅔of the oil is produced through EOR processes.

e- Total annual oil production was forecasted by extrapolating 1995– 2010 production through 2060 using a simple exponential decline curve.

f- Makeup water use was then estimated by multiplying the total annual oil production times the fraction of oil production from EOR, times the makeup water factor (1.3 bbl water/bbl oil as described earlier), times the respective water fractions (fresh versus saline/brackish). Makeup water use was calculated in this way for both the historical period of record (1995–2010) and forecasted through the year 2060. This calculation was done on the basis of aggregate regional oil production and on a county-level basis, according to their respective historical and forecast total annual oil production values.

A simple scaling was then applied to those counties outside of districts 8, 8A, and 7C according to their fresh-water use in 1995 and total injection volume in the 2002–2005 period. The state-level estimated 2008 water use for **nonprimary recovery processes is ~13 and 25.5 thousand AF for fresh and brackish water**, respectively (Figure 94 and Table 22). As expected, the spatial distribution of waterflood water use is heavily weighted toward the Permian Basin (Figure 96). We are reasonably confident in the total of 38.5 thousand AF, but less in the distribution between fresh and brackish categories.

4.2.2 Drilling

The number of holes drilled per year in the past 50 years has varied from 30,000+ to <10,000, whereas the number of oil and gas wells completed during the same period has varied from 5,000+ to <25,000 (Figure 95). The holes-drilled category includes, in addition to completed wells, dry holes, service wells, and the like. The past decade has seen a steady increase in the number of wells drilled per year in Texas, which was interrupted only by the recent economic slowdown. A significant fraction is related to recent shale-gas production (gas-well curve crossing over the oil-well curve in Figure 95), but the recent interest in unconventional oil is also visible; many other wells were drilled in conventional reservoirs.

Well drilling requires a fluid carrier to remove the cuttings and dissipate heat created at the drill bit. The fluid also keeps formation-water pressure in check. Broadly, three types of fluids are used: (1) air and air mixtures, (2) water-based muds, and (3) oil-based muds. By far the most common method involves water-based muds. Clean water is needed to optimize the mud performance. Air drilling is traditionally used in the thick unsaturated zone with no source of water nearby or low-permeability formations with sufficient strength, but it is becoming more popular (U.S. DOE, 2009, p. 55), as in the Marcellus Shale in Pennsylvania, in which many wells are drilled in the formation with little added water. For similar subsurface conditions, drilling practices differ from region to region, and we did not attempt a comprehensive study of drilling practices. Oil-based mud is typically used at greater depths or when sensitive clays, for example, could be a problem. As a general rule, a water-supply well (typically the most convenient way of obtaining water) is drilled next to the drilling site, although the amount of water used is not always metered. The amount of water required is what is needed to fill up the well bore, as well as the mud pit (must be large enough to allow time for the fine rock cutting to settle), if neither a closed loop is used nor auxiliary equipment. An additional factor is that for many wells, the mud system has to be changed, at least partly, in the course of the drilling. An approximate rule of thumb would be to multiply the borehole volume by some coefficient. Anecdotal evidence suggests that this multiplier could range from 3 to 6 or higher. Additional water is used to wash equipment to prepare the cement slurry for these wells to be completed. A

proper cement set up also requires clean water. Overall, the water used is typically fresh or slightly brackish; produced water is typically not used because it is dirty and the operator would need to treat it at a cost before using it.

Several approaches were followed to collect data on drilling-water use: (1) survey of operators in the Permian Basin (Galusky, 2010), (2) borehole-volume approach with information downloaded from the IHS database, and (3) other, less structured evidence gathered from the literature and through informal discussion with site engineers.

The last category includes documentation published by Chesapeake (2009) of 400,000 gal/well in the Barnett Shale, 600,000 gal/well in the Haynesville Shale, and 125,000 gal/well in the Eagle Ford Shale (Marcellus consumes only 100,000 gal/well). A Chesapeake Barnett well is drilled all the way using water-based mud. The Haynesville is typically much deeper than the Barnett, and the horizontal section is drilled using oil-based mud, whereas most of a Chesapeake Marcellus well is drilled using oil-based muds except for the air-drilling USDW section (M. E. Mantell, personal communication, 2010). No data were collected on the drilling approach in the Eagle Ford Shale. Computing average well-bore volume from the IHS database for the Chesapeake Barnett and Haynesville wells (17.3 and 36 thousand gallons, respectively) provides a multiplier on the order of 15. Barnett Shale survey results from Galusky (2007, p. 7 and Table 1) indicate that, in 2006, about 10% of total water use was dedicated to drilling, that is, 150,000 to 300,000 gal/well. The split between groundwater and surface water is likely to be similar to that of completion (about equal) for those fraced wells. However, the split is unknown for nonfraced wells, although likely to favor groundwater because laying pipes from surface-water bodies would be prohibitively expensive to obtain the relatively small amount of water needed for drilling. More anecdotal evidence from the Middle Pecos GCD suggests that water use for well drilling was in the range of 200,000 to 300,000 gal/well in 2009. A significant fraction of major and minor aquifers in Pecos County are brackish, however, so average fresh water is probably about half of this figure. A rule of thumb applicable at least in the Permian Basin suggests 0.3 to 1 bbl/ft, that is, between 75,000 and 250,000 gal/well for a 6,000-ft-deep well. In Texas, many wells are drilled to the 5,000- to 7,000-ft depth range because many reservoirs are located around those depths (Nicot, 2009b). Another rule of thumb heard during this study was 1 barrel of water per cubic foot of hole, which translates into a multiplier of 5.6.

The borehole-volume approach consists of extracting dimension information about all wells drilled in Texas in a given year (Table 23), correcting for those wells with no casing information (20% on average) and applying a multiplier to estimate drilling-water use. The average Texas well has a volume of ~15,000 gallons. Clearly, the deeper the well, the larger the water use. However, the increase is not linear for several reasons: borehole diameter decreases with depth in a stepwise fashion, the use of several mud systems is more likely, surface installation are larger. We initially used a multiplier of five to find average drilling-water use during the past decade of ~3,000 AF, varying from 2.4 to 4.6 thousand AF/yr. However, in light of survey returns (see later section) and increased interest in generally deeper gas shales, a multiplier of 10 seemed more realistic, resulting in an initial preliminary estimate for average drilling-water use of 6 thousand AF/yr in the past decade across the state.

The third approach consisted of accessing the information through an operator survey in the Permian Basin (Galusky, 2010) in districts 8, 8A, and 7C, which consistently represent one-third of the wells drilled in Texas (Table 24). A reasonable value used for the computation was ~130,000 gal/well (0.41 AF/well) of fresh water combined with ~500,000 gal/well (1.59

AF/well) of brackish and saline water. This computation resulted in total water use for the three districts of ~2,300 AF in 2008 (~6,300 wells spudded according to IHS database) and ~2,200 AF in 2010, amounts not predicted to grow unless shale-gas production takes hold in a strong way in West Texas.

Although not negligible at the state level, drilling water use is distributed across all oil- and gas-producing counties in the state. In 2008, about ~20,000 wells had been spudded in Texas (IHS database and RRC website). Barnett Shale Tarrant and Johnson Counties had the most wells spudded, 825 and 890, respectively. Assuming an average 0.4 million gal water use per well (conservative because vertical wells are also included in the count) results in drilling-water use of 1,000 AF in each county. Next are Permian Basin counties (Andrews, Upton, Ector, Pecos, Webb, Martin, and Midland, in decreasing order of number of wells), with 550 to ~250 wells spudded per county in 2008, resulting in 0.23 to 0.1 thousand AF per county. A final figure of 130,000 gal/well for 20,000 wells was eventually retained, leading to a **drilling-fresh-water use of 8.0 thousand AF**. Note that reuse is likely occurring in the drilling field as flowback water from fracing operations can be used for drilling additional wells. There is no data on how widespread the practice is.

Table 15. Historical water use in secondary and tertiary recovery (million barrels)

	Saltwater		Brackish Water		Fresh Water		BW	FW
	(million bbl)							
District	1980	1981	1980	1981	1980	1981	1995	1995
1	13.0	12.4	13.3	17.3	4.5	3.4		1.4
2	31.6	20.6	0.0	0.0	0.0	0.0		0.0
3	71.6	59.9	0.0	0.0	0.1	0.0		0.0
4	84.8	79.6	0.1	0.0	0.0	0.0		0.0
5	14.3	9.3	0.0	0.0	1.1	1.0		4.2
6	57.8	57.5	2.4	2.4	23.8	24.6		8.5
6E	0.5	1.6	5.1	6.2	1.0	1.0		0.8
7B	131.6	133.5	1.7	1.4	46.0	41.5		57.0
7C	53.2	52.1	8.3	6.7	5.8	4.7		1.0
8	603.8	617.2	462.7	440.4	73.5	81.2		19.3
8A	791.3	855.1	42.1	41.0	453.3	413.3		155.3
9	277.8	292.3	3.3	3.3	12.4	12.1		1.1
10	19.6	20.5	0.0	0.0	15.9	14.5		3.1
Total	**2150.9**	**2211.6**	**539.1**	**518.7**	**637.5**	**597.3**	**78.2**	**251.7**

Source: RRC (1982) and De Leon (1996)

Historical Injection 2=fromRRC1982Report.xls

Table 16. Fresh-water use in EOR operations (1995 RRC survey)

County	Fresh-Water Use (bbl)	County	Fresh-Water Use (bbl)	County	Fresh-Water Use (bbl)
Gaines	59,347,090	Frio	1,076,890	Williamson	95,238
Stephens	56,208,617	Irion	963,590	Bastrop	88,625
Hockley	42,684,399	Scurry	896,000	Ward	73,000
Yoakum	19,466,366	Gregg	818,571	Bowie	70,262
Andrews	12,520,625	Marion	640,379	Cass	54,750
Cochran	8,857,214	Franklin	628,405	Stonewall	44,147
Lubbock	8,146,162	Nolan	557,791	Panola	42,323
Dawson	5,517,713	Young	534,265	Hardin	40,783
Garza	4,448,645	Winkler	365,000	Atascosa	22,850
Leon	4,203,810	Howard	220,462	Jack	15,602
Ector	3,574,347	Martin	214,778	Archer	4,305
Anderson	3,145,589	Dickens	196,060	Coleman	3,000
Gray	3,145,143	Clay	194,280	Callahan	1,800
Hale	2,421,237	Rusk	163,173	Tom Green	375
Terry	2,139,628	Eastland	158,393	Wilson	45
Smith	1,933,184	Zavala	143,054		
Wood	1,658,113	Cooke	134,394	**Total (bbl)**	**251,716,698**
Pecos	1,257,715	Camp	120,745	**Total (AF)**	**32,444**
Lynn	1,149,368	Knox	117,233		
Mitchell	1,090,170	Wichita	100,995		

Source: De Leon (1996)

FreshWater+OilProduction_RCC1995.xls

Table 17. Number of permitted fresh-water injection wells as of January 2010

District	Injection into Nonproducing Intervals	Injection into Production Formation	Secondary Recovery	Total
01	5	18	380	403
02	1	1	0	2
03	0	1	3	4
04	3	0	5	8
05	1	0	68	69
06	3	42	244	289
6E	0	8	40	48
7B	1	39	628	668
7C	0	5	87	92
08	1	81	3,961	4,043
8A	5	368	9,075	9,448
09	2	12	112	126
10	2	30	199	231
Total	24	605	14,802	15,431

Source: Fernando De Leon (RRC, January 2010) custom data pull

Table 18. District-level total water injection volume vs. waterflood volumes (1998)

1998—All volumes in bbl						
District	**Disposal in nonprod. zone**	**Disposal in prod. zone**	**Waterflood**	**Other**	**Total**	**Water-flood/ Total**
1	221,676,839	36,224,868	21,626,651	0	279,528,358	7.7%
2	121,625,598	29,673,891	58,255,145	0	209,554,634	27.8%
3	378,303,159	77,043,184	38,606,639	1,653,895	495,606,877	7.8%
4	77,713,906	19,949,912	29,217,354	0	126,881,172	23.0%
5	24,783,981	29,833,615	15,594,964	0	70,212,560	22.2%
6	122,873,017	73,922,979	53,064,690	0	249,860,686	21.2%
6E	0	356,784,106	26,290,016	0	383,074,122	6.9%
7B	25,100,019	28,512,343	321,250,271	0	374,862,633	**85.7%**
7C	45,307,377	73,054,222	79,496,652	0	197,858,251	40.2%
8	139,510,861	208,640,430	1,203,840,221	341,660	1,552,333,172	**77.6%**
8A	68,752,368	115,105,922	1,211,495,952	0	1,395,354,242	**86.8%**
9	24,556,396	36,674,585	198,195,141	15,370	259,441,492	76.4%
10	25,714,081	24,599,525	20,115,688	0	70,429,294	28.6%
Totals:	**1,275,917,602**	**1,110,019,582**	**3,277,049,384**	**2,010,925**	**5,664,997,493**	**57.8%**

Source: RRC website IniectionVolume 2002 RRC +1998-2001.xls
http://www.rrc.state.tx.us/data/wells/statewidewells.php
Note: includes all water types (fresh to saline, produced and others)

Table 19. District-level total water-injection volume vs. waterflood volumes (2002)

Year 2002—All volumes in bbl						
District	Disposal in nonprod. zone	Disposal in prod. zone	Waterflood	Other	Total	Waterflood / Total
1	209,482,615	29,795,963	12,464,957	0	251,743,535	5.0%
2	112,608,696	20,504,067	56,234,669	0	189,347,432	29.7%
3	323,989,781	71,070,254	23,308,202	292,511	418,660,748	5.6%
4	84,577,088	13,963,848	21,024,812	0	119,565,748	17.6%
5	36,118,853	28,867,538	15,452,586	0	80,438,977	19.2%
6	149,292,665	86,293,340	41,801,873	0	277,387,878	15.1%
6E	158,881	348,180,269	31,694,999	0	380,034,149	8.3%
7B	24,602,044	26,477,559	252,445,261	1,528	303,526,392	**83.2%**
7C	40,711,999	63,911,860	88,144,873	0	192,768,732	45.7%
8	152,802,343	194,498,880	1,163,394,951	159,900	1,510,856,074	**77.0%**
8A	65,416,720	114,281,934	1,258,302,110	0	1,438,000,764	**87.5%**
9	26,395,288	30,699,374	156,616,151	27,386	213,738,199	73.3%
10	16,073,237	19,443,141	16,880,842	0	52,397,220	32.2%
Totals:	**1,242,230,210**	**1,047,988,027**	**3,137,766,286**	**481,325**	**5,428,465,848**	**57.8%**

Source: RRC website InjectionVolume_2002_RRC_+1998-2001.xls
http://www.rrc.state.tx.us/data/wells/statewidewells.php
Note: includes all water types (fresh to saline, produced and others)

Table 20. Estimated district-level fraction of fresh-water in waterflood water volumes

District	Waterflood water use average (all types) 1998–2002 (million bbl)	1995 fresh-water use (million bbl)	Fresh / Total	Fresh + Brack / Total*
01	267.0	1.43	0.53%	0.70%
02				
03	496.5	0.04	0.01%	0.01%
04				
05	81.6	4.20	5.15%	6.75%
06	288.4	8.46	2.93%	3.84%
6E	420.7	0.82	0.19%	0.00%
7B	393.8	56.97	14.47%	18.95%
7C	223.6	0.96	**0.43%**	**0.56%**
08	1,689.3	19.32	**1.14%**	**1.50%**
8A	1,578.3	155.27	**9.84%**	**12.89%**
09	252.1	1.10	0.44%	0.57%
10	69.6	3.15	4.52%	5.92%
Totals	**5,760.8**	**251.72**	**4.37%**	**5.59%**

InjectionVolume_2002_RRC_+1998-2001.xls

*Obtained by multiplying by the same coefficient of 1.31 for all districts to account for brackish-water use

Table 21. Initial guess for extrapolated district-level fresh-water use for waterfloods

District	1998–2002 Average Fraction of Waterflood vs. Total Injection	1995 Fresh-Water Use Fraction vs. Total Waterflood	Average 2007–2008 Total Injection (million bbl)	Extrapolated Fresh-Water Use (thousand AF)
01	6.1%	0.53%	485.0	**0.02**
02	28.5%	0%	[213.7]	
03	6.3%	0.01%	469.0	**0.00**
04	20.3%	0%	[137.0]	
05	19.8%	5.15%	197.0	**0.26**
06	11.7%	2.93%	756.6	**0.15**
7B	84.8%	14.47%	388.0	**6.13**
7C	42.9%	0.43%	287.5	**0.07**
08	77.2%	1.14%	1,652.7	**1.88**
8A	87.5%	9.84%	1,716.3	**19.03**
09	74.0%	0.44%	263.9	**0.11**
10	31.5%	4.52%	105.7	**0.19**
Total	58.2%	4.37%	6321.62	**27.85**

IniectionVolume 2002 RRC +1998-2001 1.xls

Table 22. County-level estimate of fresh-water use for waterfloods

County	Fresh 2008	Fresh 2010	Brack 2008	Brack 2010	County	Fresh 2008	Fresh 2010	Brack. 2008	Brack. 2010
State Total	**12.95**	**7.87**	**25.52**	**29.91**					
Anderson	0.013	0.008	0.026	0.031	Lipscomb	0.005	0.003	0.009	0.011
Andrews	0.552	0.384	1.243	1.457	Loving	0.038	0.074	0.240	0.282
Archer	0.005	0.003	0.009	0.010	Lubbock	0.359	1.307	4.239	4.968
Atascosa	0.001	0.001	0.002	0.002	Lynn	0.051	0.207	0.670	0.785
Baylor	0.000	0.000	0.001	0.001	Marion	0.001	0.001	0.002	0.002
Borden	0.123	0.000	0.000	0.000	Martin	0.009	0.084	0.273	0.320
Brown	0.008	0.005	0.016	0.018	Maverick	0.001	0.001	0.003	0.003
Callahan	0.029	0.018	0.057	0.067	McCulloch	0.010	0.009	0.029	0.034
Camp	0.004	0.003	0.009	0.010	McMullen	0.001	0.000	0.001	0.001
Carson	0.001	0.000	0.001	0.001	Menard	0.002	0.250	0.809	0.948
Clay	0.002	0.001	0.004	0.004	Midland	0.328	0.035	0.114	0.134
Cochran	0.390	0.005	0.017	0.020	Mitchell	0.048	0.003	0.009	0.011
Coke	0.034	0.109	0.355	0.416	Montague	0.006	0.004	0.012	0.014
Coleman	0.035	0.021	0.068	0.080	Moore	0.001	0.001	0.003	0.003
Comanche	0.001	0.000	0.001	0.001	Motley	0.004	0.027	0.089	0.104
Concho	0.027	0.108	0.351	0.412	Navarro	0.004	0.002	0.007	0.008
Cooke	0.007	0.004	0.014	0.016	Nolan	0.074	0.045	0.146	0.171
Cottle	0.002	0.007	0.022	0.026	Ochiltree	0.006	0.004	0.012	0.015
Crane	0.399	0.027	0.086	0.101	Oldham	0.005	0.003	0.010	0.012

County	Fresh 2008	Fresh 2010	Brack 2008	Brack 2010	County	Fresh 2008	Fresh 2010	Brack. 2008	Brack. 2010
Crockett	0.086	0.007	0.021	0.025	Palo Pinto	0.029	0.018	0.058	0.068
Crosby	0.020	0.228	0.739	0.866	Pecos	0.055	0.066	0.212	0.249
Culberson	0.007	0.033	0.108	0.127	Potter	0.001	0.000	0.001	0.002
Dawson	0.243	0.039	0.125	0.146	Reagan	0.152	0.024	0.077	0.090
Dickens	0.009	0.000	0.000	0.000	Red River	0.001	0.001	0.003	0.003
Dimmit	0.001	0.000	0.001	0.002	Reeves	0.027	0.019	0.061	0.071
Eastland	0.115	0.070	0.228	0.267	Runnels	0.027	0.060	0.194	0.228
Ector	0.158	0.019	0.061	0.072	Rusk	0.019	0.011	0.037	0.044
Fisher	0.150	0.091	0.295	0.345	Schleicher	0.016	0.030	0.096	0.112
Floyd	0.000	0.031	0.101	0.119	Scurry	0.039	0.000	0.000	0.000
Foard	0.001	0.001	0.002	0.002	Shackelford	0.075	0.046	0.148	0.173
Franklin	0.002	0.001	0.004	0.004	Sherman	0.003	0.002	0.006	0.007
Freestone	0.002	0.001	0.004	0.005	Smith	0.007	0.004	0.014	0.016
Gaines	2.616	0.002	0.007	0.008	Stephens	1.786	1.086	3.520	4.126
Garza	0.196	0.011	0.036	0.042	Sterling	0.045	0.007	0.023	0.027
Glasscock	0.156	0.085	0.276	0.324	Stonewall	0.218	0.132	0.430	0.503
Gray	0.024	0.014	0.047	0.055	Sutton	0.001	0.001	0.005	0.005
Grayson	0.002	0.001	0.004	0.004	Taylor	0.025	0.015	0.049	0.057
Hale	0.107	0.271	0.880	1.031	Terrell	0.004	0.106	0.343	0.401
Hansford	0.002	0.001	0.003	0.004	Terry	0.094	0.019	0.061	0.072
Hartley	0.003	0.002	0.005	0.006	Throckmorton	0.069	0.042	0.137	0.160
Haskell	0.031	0.019	0.061	0.072	Titus	0.003	0.002	0.005	0.006
Hockley	1.881	0.001	0.004	0.005	Tom Green	0.032	0.011	0.036	0.042
Hopkins	0.015	0.009	0.029	0.034	Upshur	0.012	0.007	0.024	0.028
Howard	0.010	0.014	0.046	0.053	Upton	0.315	0.000	0.001	0.002
Hutchinson	0.006	0.004	0.013	0.015	Van Zandt	0.019	0.012	0.038	0.044
Irion	0.042	0.169	0.548	0.642	Ward	0.003	0.003	0.010	0.012
Jack	0.001	0.001	0.002	0.002	Wheeler	0.001	0.000	0.001	0.002
Jones	0.041	0.025	0.080	0.094	Wichita	0.020	0.012	0.040	0.047
Kent	0.297	0.006	0.019	0.023	Wilbarger	0.003	0.002	0.005	0.006
King	0.121	1.818	5.893	6.907	Wilson	0.001	0.000	0.001	0.001
Knox	0.001	0.001	0.002	0.003	Winkler	0.016	0.022	0.071	0.083
Lamb	0.013	0.136	0.442	0.518	Wood	0.006	0.004	0.012	0.014
Leon	0.019	0.011	0.037	0.043	Yoakum	0.858	0.219	0.709	0.832
Limestone	0.001	0.001	0.002	0.003	Young	0.003	0.002	0.005	0.006

InjectionVolume_2002_RRC_+1998-2001_1.xls

Table 23. Estimated and calculated oil and gas well drilling water use

	No. of Wells w/ Casing Data	Average Borehole Volume (gal/well)	Total BH Volume (Mgal)	Total BH Volume (Th. AF)	Total No. of Wells	Corrected Total BH Volume (Th. AF)	Multiplier	Water Use (Th. AF /yr)
2009	9,019	16,093	145.1	0.445	11,542	0.570	10	**5.70**
2008	16,311	15,585	254.2	0.780	19,121	0.915	10	**9.15**
2007	14,513	15,168	220.1	0.676	16,930	0.788	10	**7.88**
2006	13,273	14,890	197.6	0.607	15,832	0.723	10	**7.23**
2005	11,535	15,744	181.6	0.557	13,929	0.673	10	**6.73**
2004	9,964	15,851	157.9	0.485	12,488	0.607	10	**6.07**
2003	9,067	15,709	142.4	0.437	11,539	0.556	10	**5.56**
2002	7,013	16,203	113.6	0.349	9,146	0.455	10	**4.55**
2001	8,676	15,628	135.6	0.416	11,504	0.552	10	**5.52**
2000	7,412	14,897	110.4	0.339	10,411	0.476	10	**4.76**

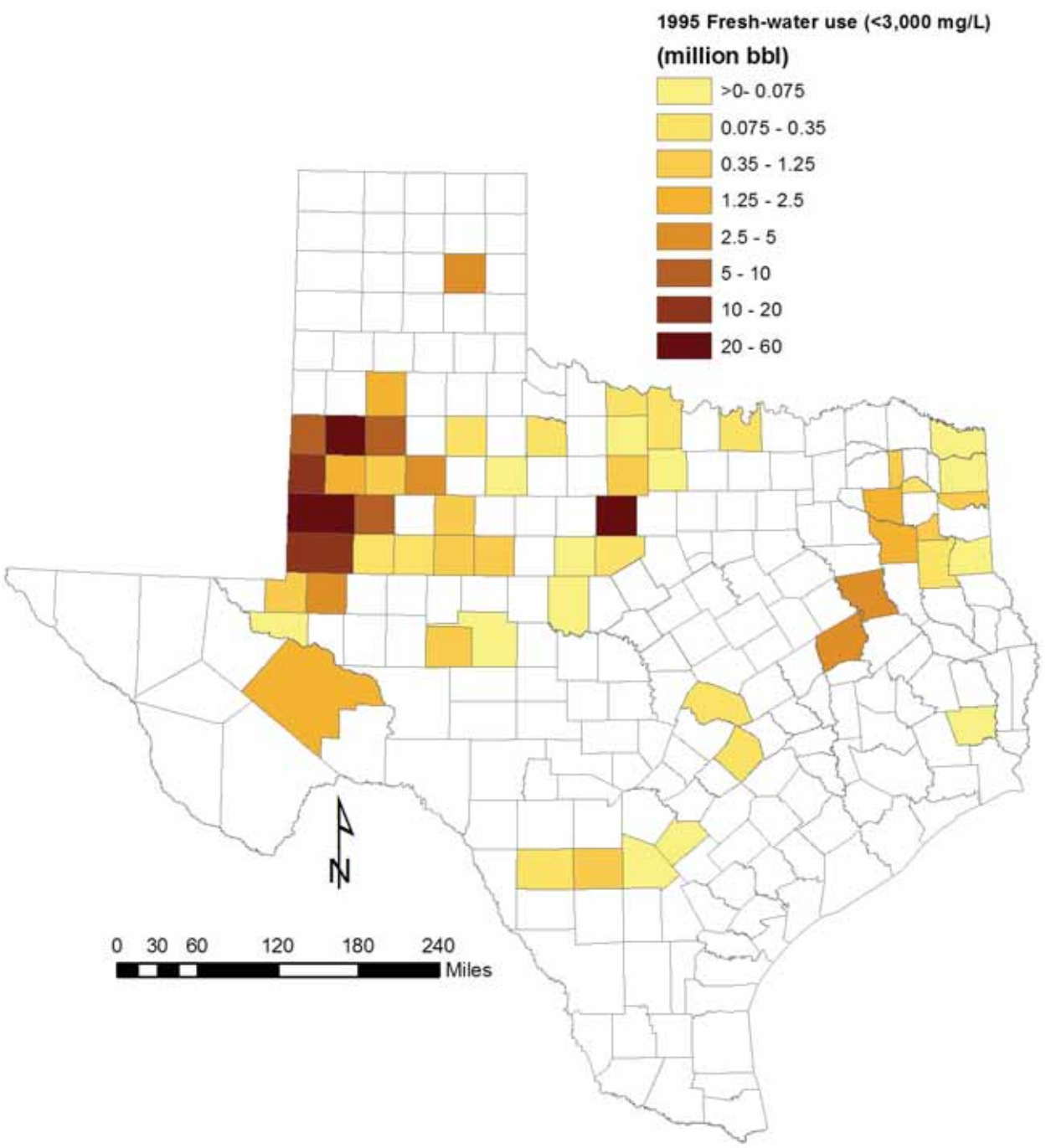
Source: IHS database

Results 2000-2009 1.xls.xls

Table 24. New drill per district

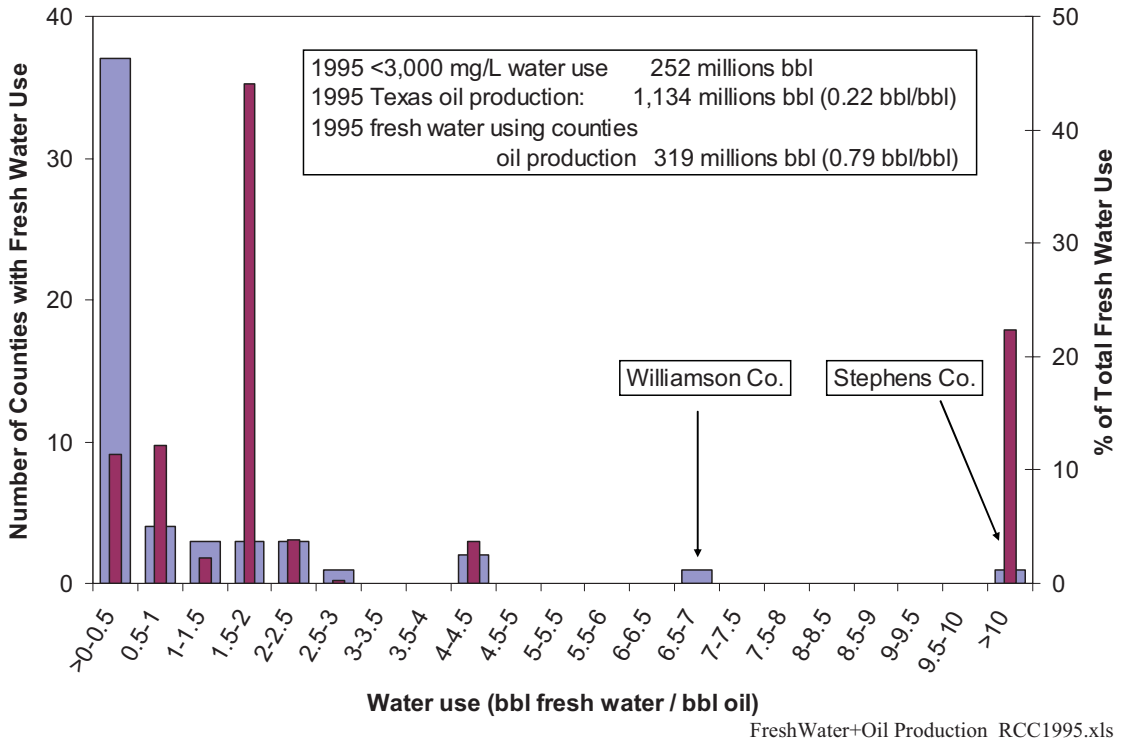
District	01	02	03	04	05	06	7B	7C	08	8A	09	10	Total
2006	369	510	451	1,354	555	1612	409	1,539	1,557	778	1,614	1,003	12,188
2007	354	398	422	982	621	1,968	327	1,565	1,789	698	2,214	952	12,291
2008	428	447	496	1,162	678	1,884	689	2,033	2,368	532	3,492	1,046	15,255

Source: RRC website



Source: 1995 RRC survey

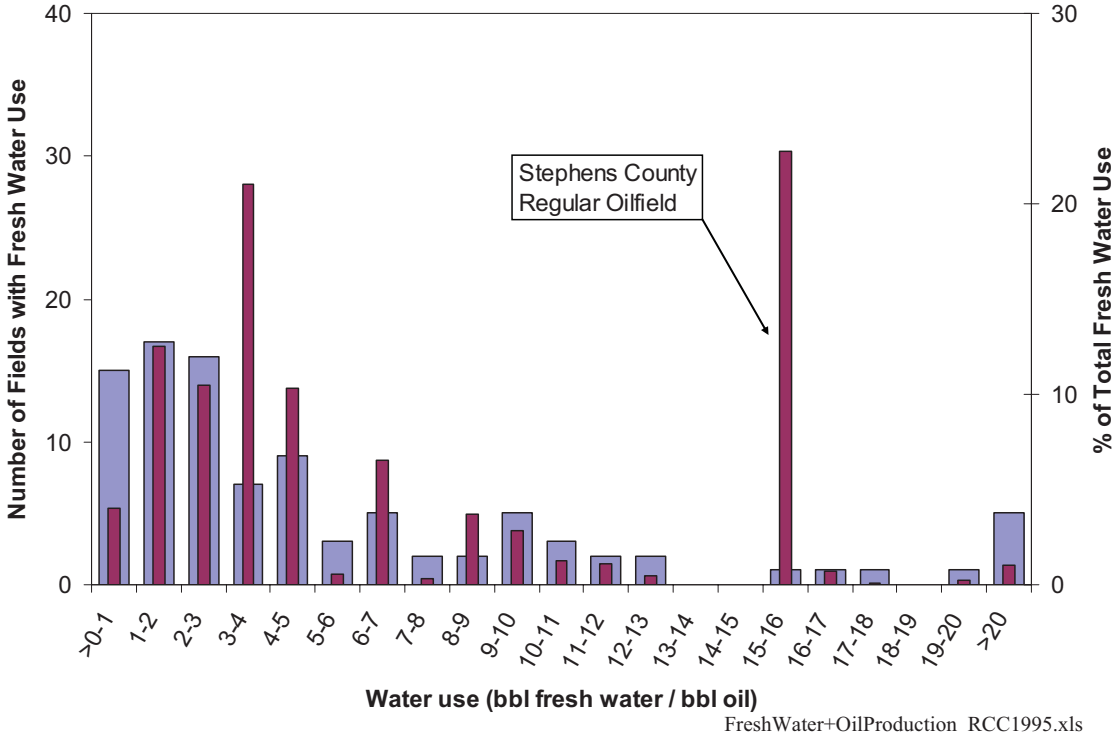
Figure 83. Map of counties using fresh water in EOR operations according to the 1995 RRC data (1 million bbl = 129 AF)



FreshWater+Oil Production RCC1995.xls

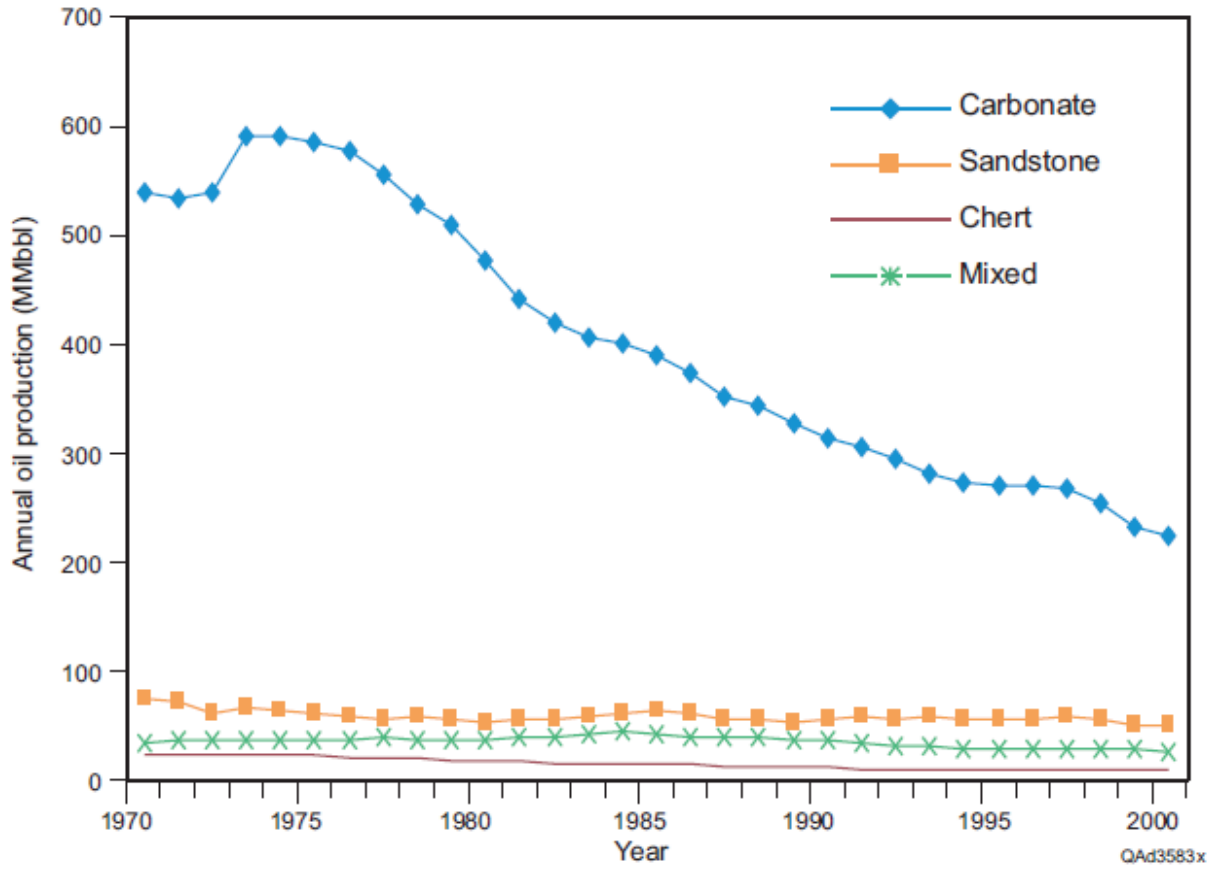
Note: obtained by dividing fresh-water use as reported by RRC by county production regardless of the actual number of fields being waterflooded

Figure 84. Histogram (year 1995) of county-level waterflood water-use coefficient (wide columns) and fraction of total fresh-water use for each bin



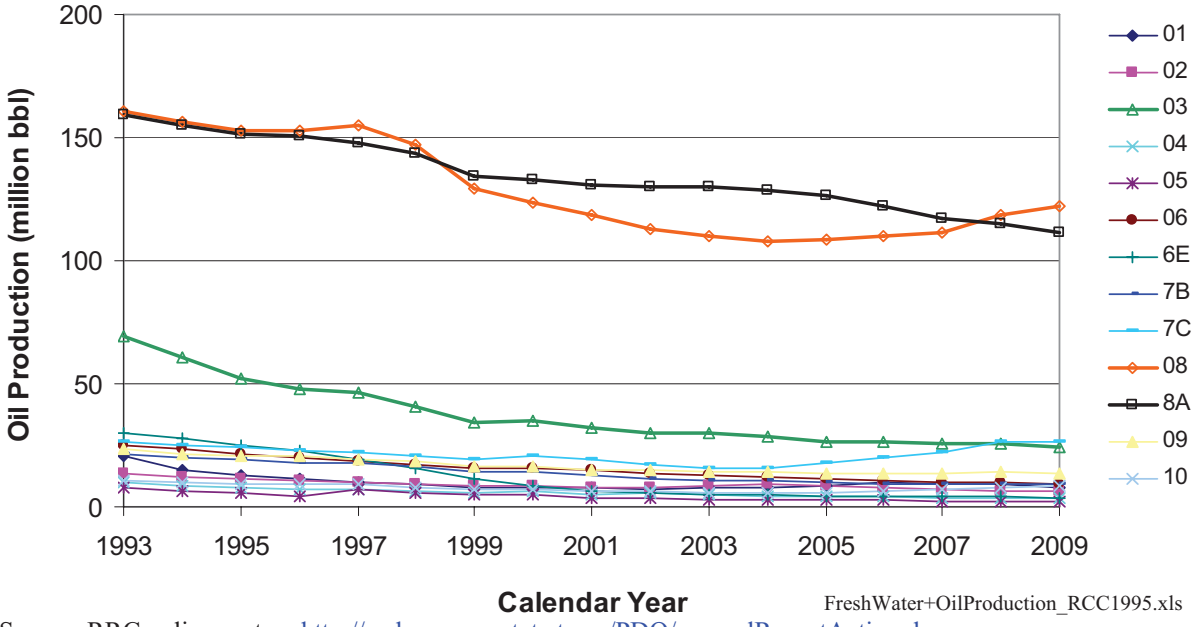
FreshWater+OilProduction RCC1995.xls

Figure 85. Histogram (year 1995) of water-use coefficient in waterflooded oil fields (wide columns) and fraction of total fresh-water use for each bin



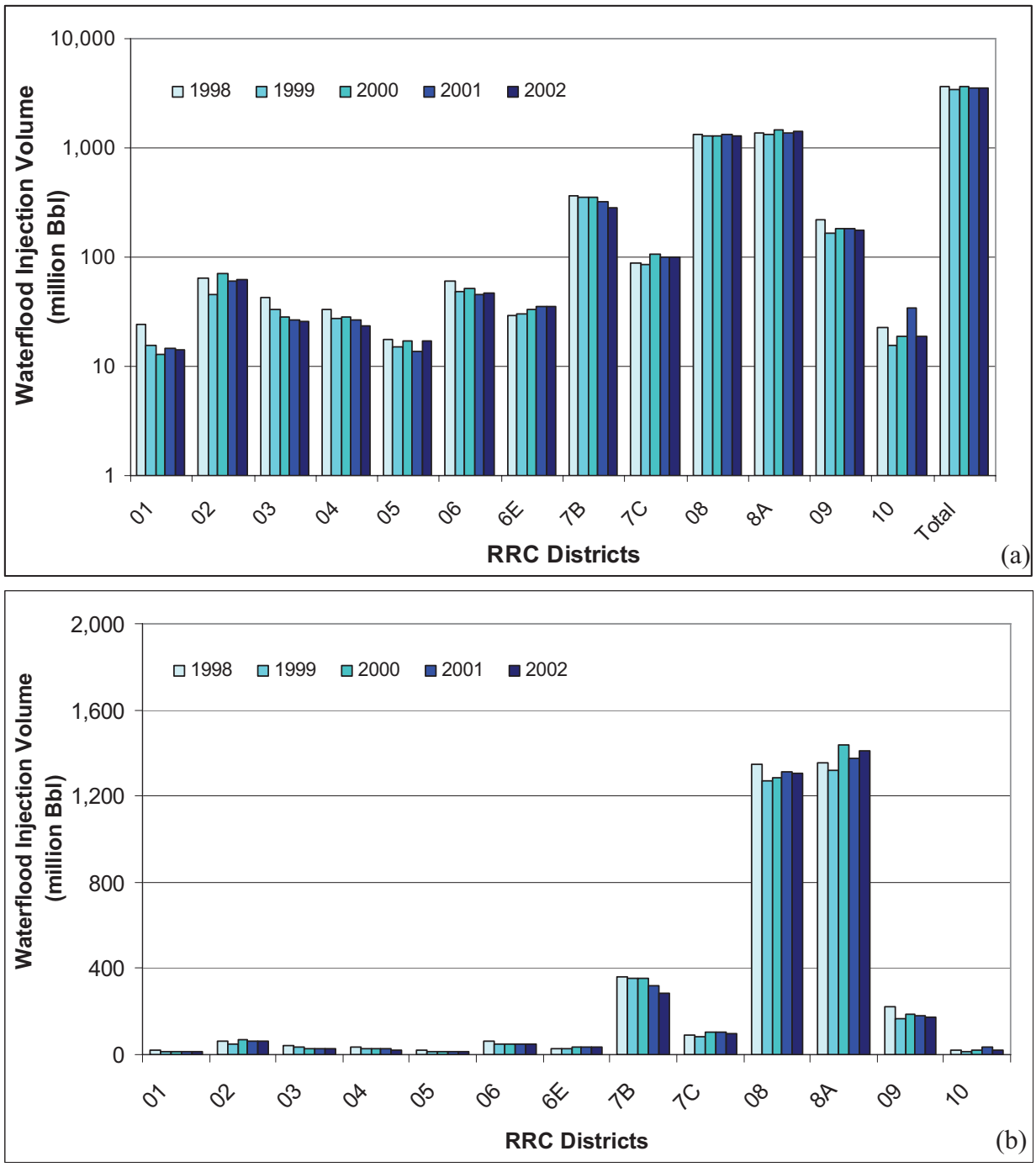
Source : Dutton et al. (2005a, Fig. 130)

Figure 86. Production histories of significant-sized oil reservoirs in the Permian Basin by lithology



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do

Figure 87. Annual oil production per district (1993–2009)

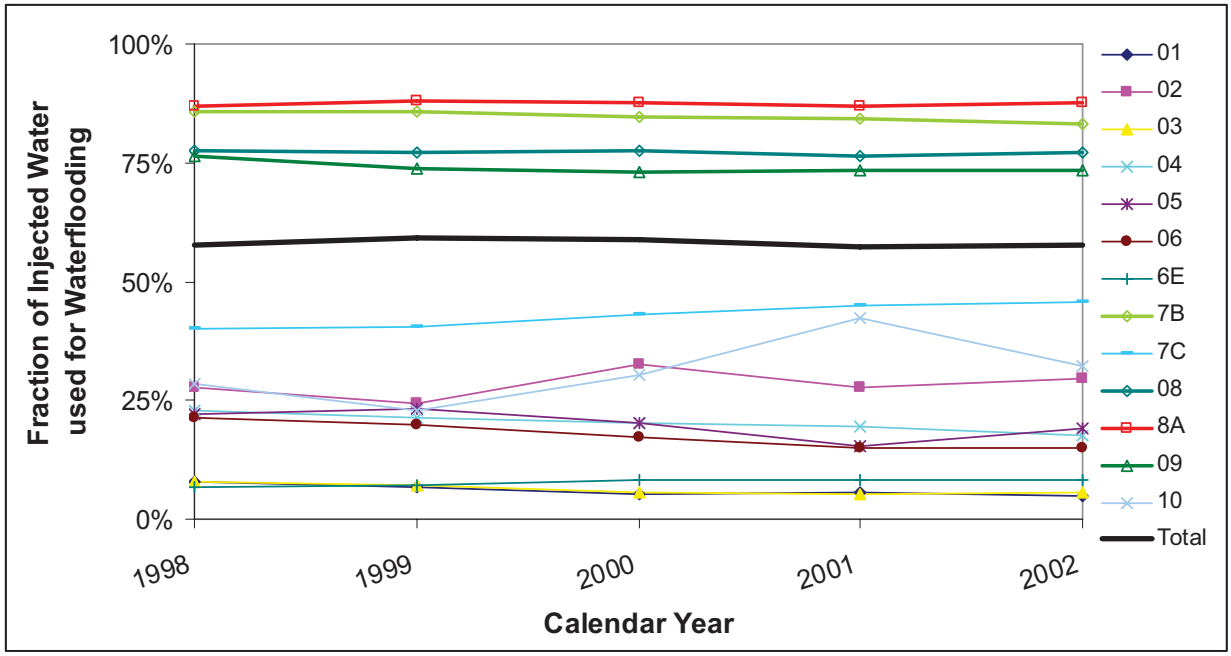


InjectionVolume 2002 RRC +1998-2001.xls

Source: RRC website http://www.rrc.state.tx.us/data/wells/statewidewells.php

Note: figures were corrected by the statewide correction factor for incomplete data (typically 10% more than reported)

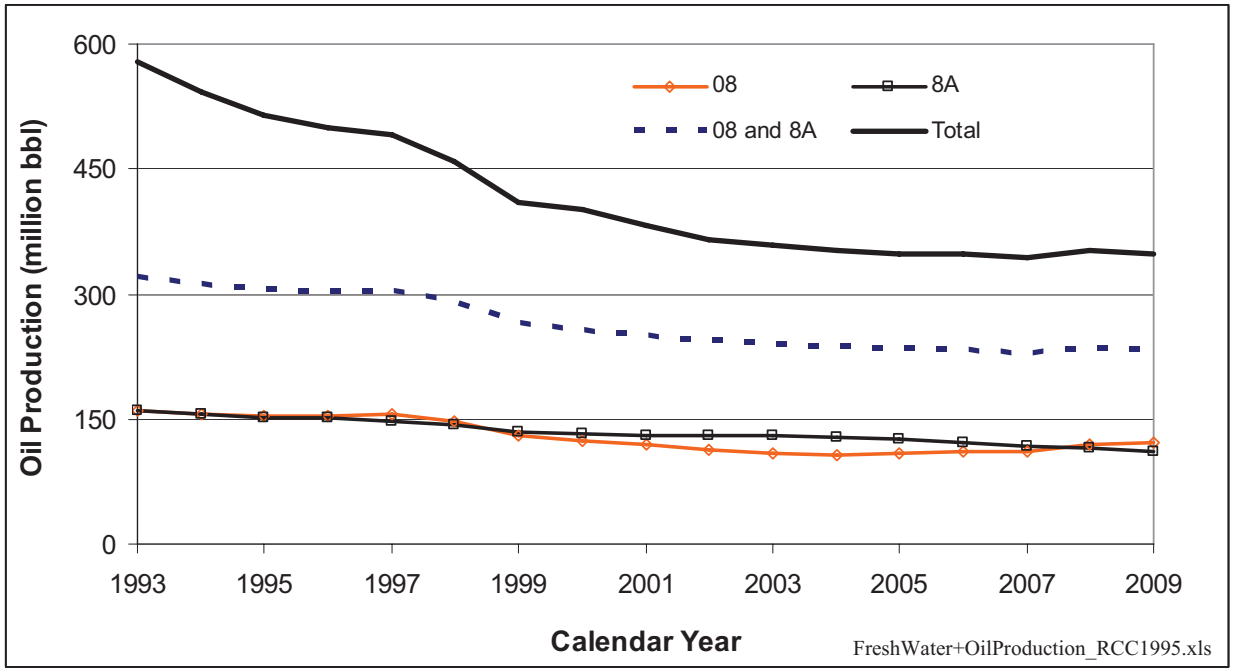
Figure 88. RRC district-level annual waterflood-dedicated injection volume in Texas (1998–2002): (a) log scale, (b) linear scale



Source: RRC website
http://www.rrc.state.tx.us/data/wells/statewidewells.php

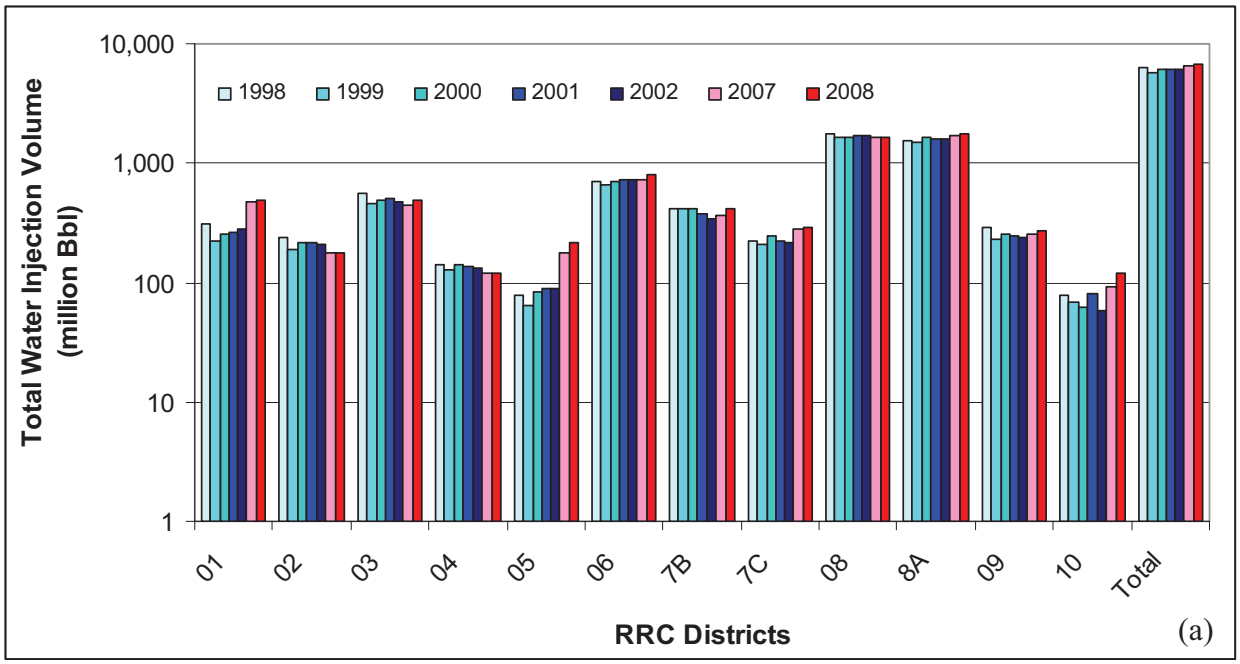
InjectionVolume 2002 RRC +1998-2001.xls

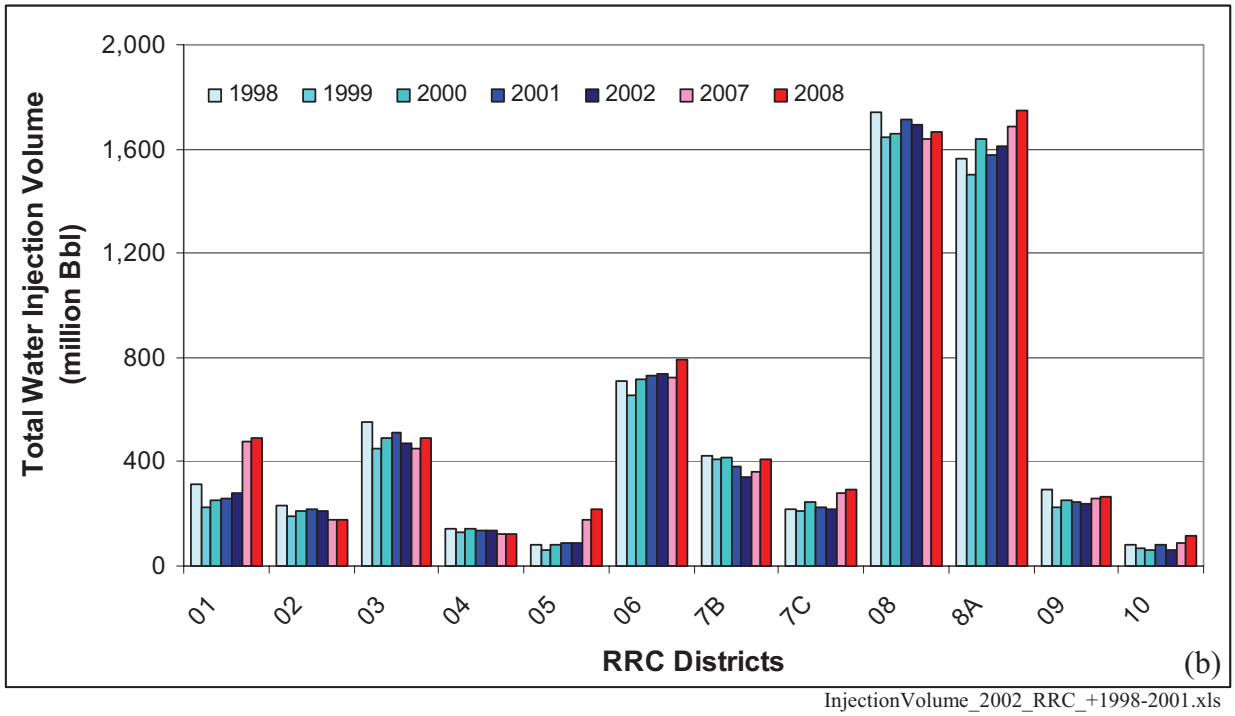
Figure 89. RRC district-level fraction of injected water (of all types) used for waterflooding



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do

Figure 90. Oil production in districts 8 and 8A





InjectionVolume_2002_RRC_+1998-2001.xls

Source: RRC website http://www.rrc.state.tx.us/data/wells/statewidewells.php for years 1998 to 2002 and http://webapps.rrc.state.tx.us/H10/h10PublicMain.do for years 2007 and 2008
Note: districts 6 and 6E are now combined

Figure 91. RRC district annual total water (of all types) injection volume (1998–2002 and 2007–2008): (a) log scale, (b) linear scale

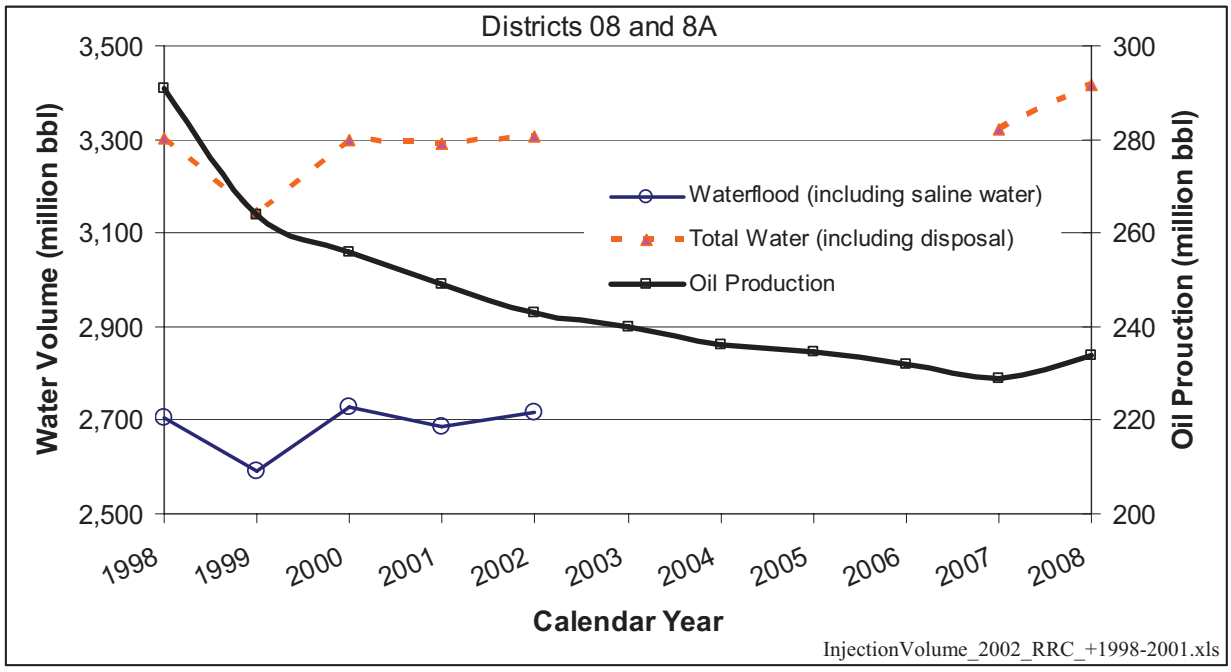
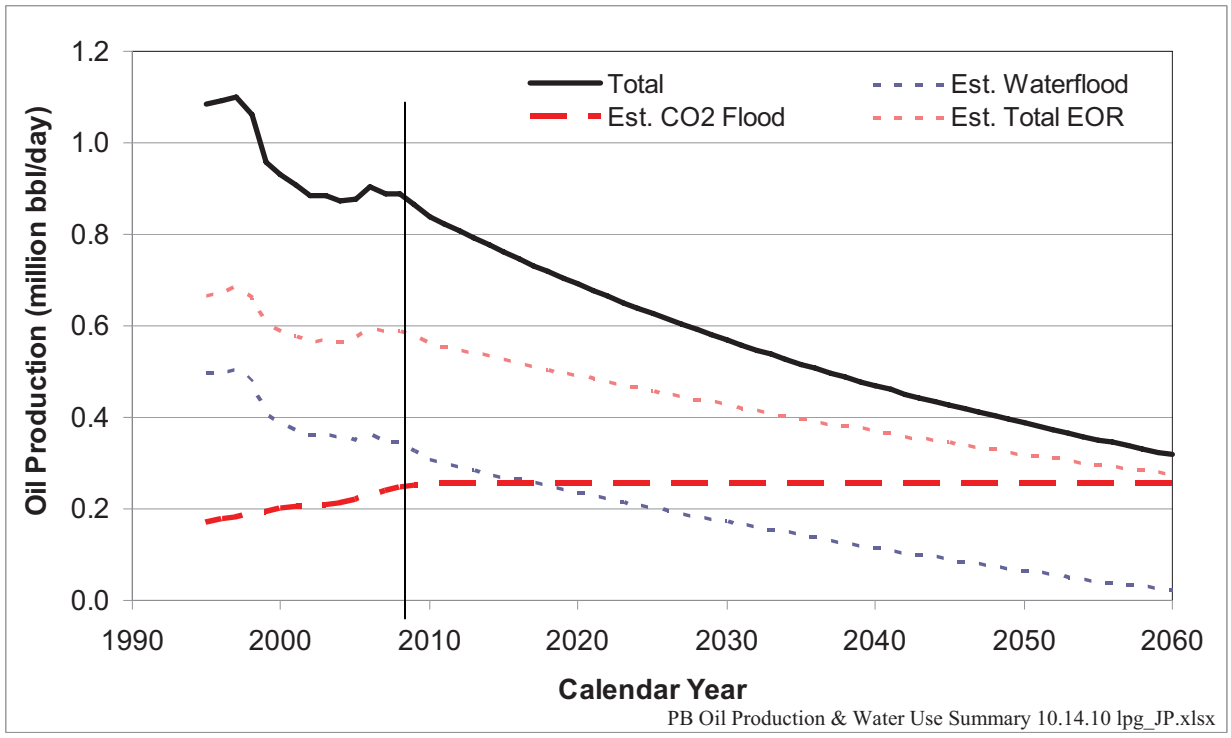
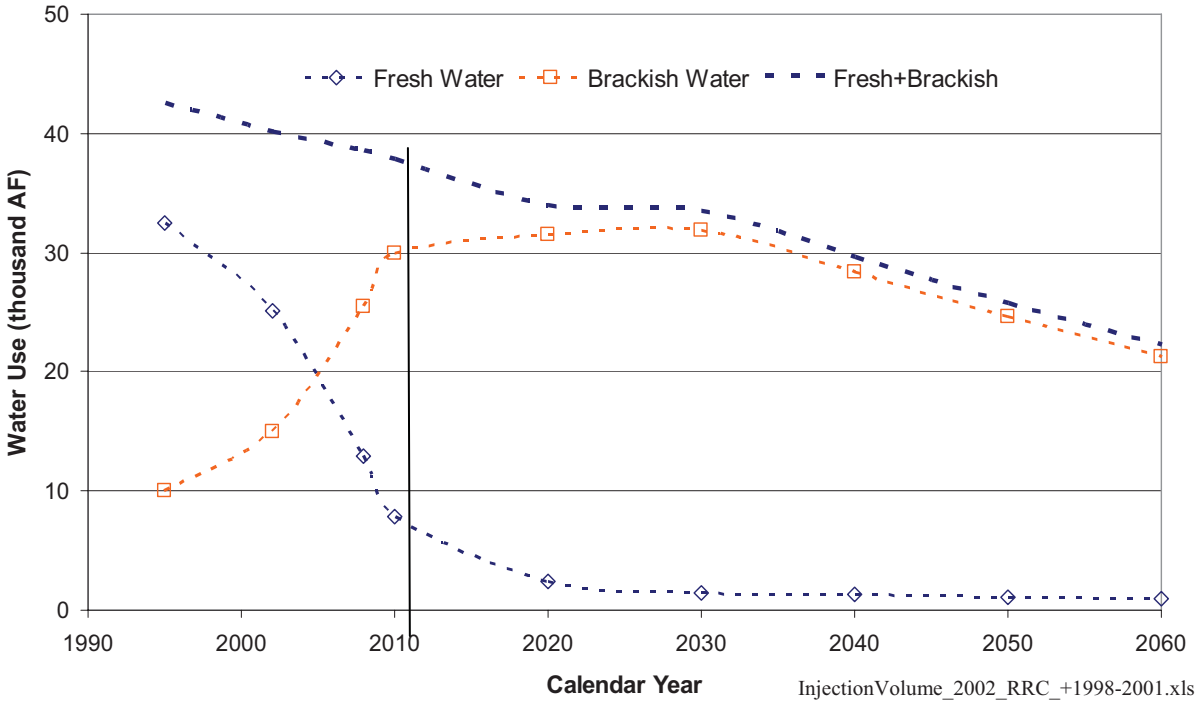


Figure 92. Comparison of oil production and water injection in RRC districts 08 and 8A (1998–2008)



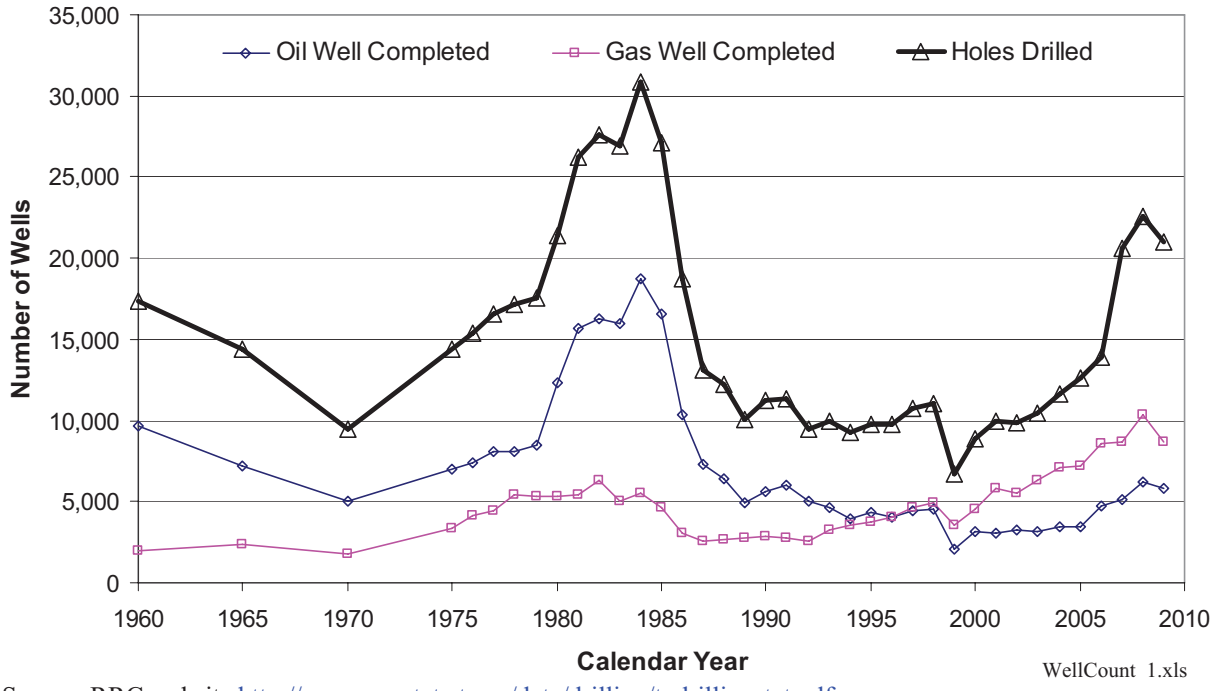
Note: data only for historical total production

Figure 93. Historical and forecast for oil production in districts 8, 8A, and 7C



Note: Only data points are from 1995 RRC survey

Figure 94. Estimated current and projected fresh- and brackish-water use for pressure maintenance and secondary and tertiary recovery operations



Source: RRC website http://www.rrc.state.tx.us/data/drilling/txdrillingstat.pdf
Note: completions include mostly new drills but also re-entered and recompleted wells (10-15% of total)

Figure 95. Number of holes drilled and of oil and gas wells completed in Texas between 1960 and 2009

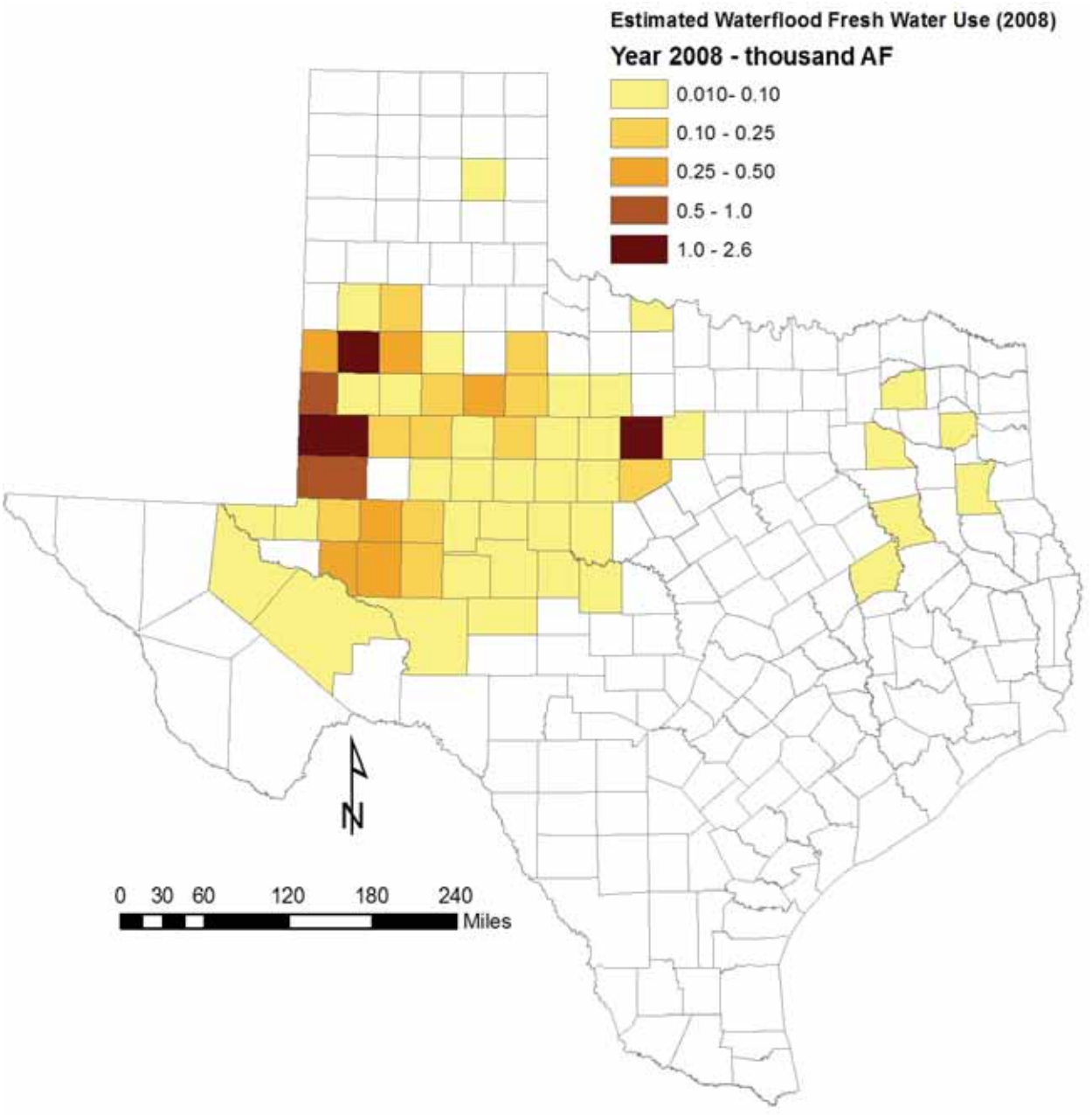


Figure 96. Estimated fresh-water use for waterfloods (2008)

4.3 Coal and Lignite

Total coal production for 2009 was >1 billion short tons for the country, 35+ million short tons of which the state of Texas produced (Table 1). Currently Texas has 11 active coal mines or groups of mines, with 2 mines (Kosse and Twin Oak mines) coming fully online in the next few years (Figure 97).Total production has been decreasing for 2 decades (Figure 98 with more details in Figure 100). All mines are above ground, mining lignite grade resources to a depth of 250 ft. All coal operations in Texas are currently mine-mouth, meaning the coal is used to power a power plant or other facility close to the mine. All mines with significant production in the past decades are still in operation, except for Sandow transitioning to the adjoining Three Oaks, both operated by ALCOA, Inc., (Williams, 2004) and the two Gibbons Creek locations (operated by the Texas Municipal Power Agency, TMPA–Bryan College Station), idle since 1996. The survey went only to current operators. From north to south, mines with recent activity as listed on the RRC website are given in Table 25.

In general, coal-mining processes require water during operations for activities such as dust suppression, waste disposal, reclamation and revegetation, coal washing, transportation, and drilling. In Texas, coal mining does not require drilling, coal washing, or transportation by slurry pipeline, and water use is limited to dust suppression and equipment washing. However, there is a need for dewatering and depressurization for most mines (Table 26). The water pumped is either discharged into a lake or stream or first discharged into a retention or sedimentation pond and then routed to a lake or stream. Therefore, once the water has been initially pumped from the ground to allow initial mining to occur, the water becomes available for use as surface water. Many mines also contract additional water from water-supply wells and water rights in order to supply fresh water to office operations (Table 27). Additionally, water for mining activities such as dust suppression and hauling activities may come either from these separate water-supply wells or from the retention ponds. Tracking where the water is routed, from where and what it is used, and the exact amount of consumption prove to be a difficult task. Whereas agencies track water pumped for operations and discharged into local surface waters, no central agencies tracks the entire operation when it comes to mining. The TWDB sends a survey to operators for groundwater pumped from water-supply wells, whereas the RRC tracks water pumped for depressurization and dewatering. Additionally, mining operators must report water-quality information on discharged water to lakes and streams to TCEQ. In order to further delineate the data, a questionnaire (Appendix D) was sent to mining operators regarding their water usage via TMRA.

In 2009, 37.1 million short tons of lignite was produced in the state, requiring production of 25.7 thousand AF of water and resulting in an average raw water use of 227.5 gal/st. However, including only consumption (and not dewatering), the same coal production required only 2.6 thousand AF or 22.8 gal/st. For comparison purposes, Chan et al. (2006) reported that, in 2003, given national coal-production statistics, a rough estimate of overall water required for coal extraction (mining and washing) ranged roughly from 86 to 235 million gal/day for an overall coal production of 1,071.7 million short tons, including 86.4 million short tons of lignite (EIA) (30 to 80 gal/st). These nationwide numbers represent a mix of uses, coal washing for Appalachian and interior coals, depressurization for lignite, and slurry pipelines.

The Sandow mine used to contribute a large fraction of total coal-mining water use (Figure 99), more than half of the ~40,000 AF/yr of produced groundwater until 2008. The current overall

amount is <20,000 AF/yr. Currently no mine comes close to the threshold of 10 thousand AF/yr. However, surface water is also used in some mines, according to data we collected for the years 2009–2010. Overall, we assumed that the amount and distribution of the water used in 2009–2010 are very similar to those used in 2008 (year chosen as representative) in the coal industry.

Luminant mines in East Texas (Monticello Thermo, Monticello Winfield, Oak Hill, Martin Lake, and Big Brown) have a total water use of between 1 and 2.5 thousand AF/yr, which is mostly due to overburden dewatering, do not need to be depressurized (or very little), and have to pump supplementary (variable across mines) amounts of water to satisfy their operational needs. All of the water is fresh and is used mostly for dust suppression. An additional mine in the same Sabine Uplift area (South Hallsville in Harrison County operated by Sabine Mining Company) shows a larger water volume being processed at 5.8 thousand AF/yr, but that includes no groundwater pumping for overburden dewatering or for depressurization. The operating technique here appears to allow for overburden seepage to collect in the pit and mix with surface water.

Central Texas mines (including Jewett, Calvert/Twin Oak, Sandow/Three Oaks) are characterized by some depressurization pumping. Levels of depressurization and dewatering vary considerably across mines. Mines located in the Calvert Bluff Formation above the prolific Simsboro aquifer of Central Texas (between the Colorado and Trinity Rivers) are forced to produce large amounts of water to depressurize and avoid heaving of the mine floor (for example, Harden and Jaffre, 2004). The Sandow mine in Milam County used to pump large amounts of water from the Simsboro, in excess of 20 thousand AF/yr.

Gibbons Creek and San Miguel mines tap the Jackson Group lignite, not the Wilcox. The San Miguel mine does produce groundwater, but it is saline and is reinjected into the subsurface. For the purpose of this study, the San Miguel mine has zero water use. Two new mines will be developed in the future: Twin Oaks, next to the current Calvert mine in Robertson County and Kosse Strip in Limestone County. They will be discussed in the Future Use section.

Table 28 summarizes our findings: a total of 25.6 thousand AF is pumped, only 2.6 thousand AF of which is consumed. Most is groundwater (18.4 thousand AF), 1.1 thousand AF of which is consumed.

Table 25. Lignite and coal-mining operations in Texas

Name	County	Current Operator	Cumul. Prod. 1976–2007 (million st)[A]	Water-Use Range (thousand AF/yr)	Status
Monticello Thermo	Hopkins	Luminant	35.4	~0.9	Active in 2009
Monticello Winfield	Titus	Luminant	268.1	0.6–1.0	Active in 2009
Darco	*Harrison*	*Norit Americas Inc.*	*6.8*		*Not in operation 2001 last prod.*
Hallsville	Harrison	Sabine Mining Company	80.4	~5.8	Active in 2009
Oak Hill	Rusk	Luminant	101.2	1.2–1.7	Active in 2009
Martin Lake	Panola	Luminant	265.9	~1.0	Active in 2009
Big Brown	Freestone	Luminant	160.7	~2.5	Active in 2009
Jewett	Freestone/ Leon	Tx Westmoreland Coal Company (NRG)	167.7	~2.0	Active in 2009
Calvert	Robertson	Walnut Creek Company	32.6	7.2	Active in 2009
Sandow	*Milam*	*ALCOA Inc.*	151.0	*>25 1990–2008 average*	*Not in operation 2005 last prod.*
Three Oaks	Bastrop/Lee	ALCOA Inc.	13.7	4.0-5.0	Active in 2009
Gibbons Creek	*Grimes*	*TMPA*	*43.0*		*Not in operation 1996 last prod.*
Powell Bend		*LCRA*	*1.6*		*No longer permitted 1993 last prod.*
San Miguel	Atascosa/ McMullen	San Miguel Electric Cooperative	80.2	0.2 saline	No fresh or brackish water use
Little Bull Creek		*Amistad Fuel Company*	*0.43*		*No longer permitted 1987 last prod.*
Eagle Pass	*Maverick*	*Dos Republicas Resources Co., Inc.*	*0*		*Not (ever?) in operation.*
Palafos, Rachal, Trevino	*Webb*	*Farco Mining, Inc.*	*7.2*		*Not in operation 2004 last prod.*
Thurber		*Thurber Coal Company*	*0.46*		*No longer permitted 1983 last prod.*

Note: mine locations not in operation are in italics in smaller print
[A]: RRC website file tx_coal.xls

Table 26. Water fate for current lignite operations in Texas

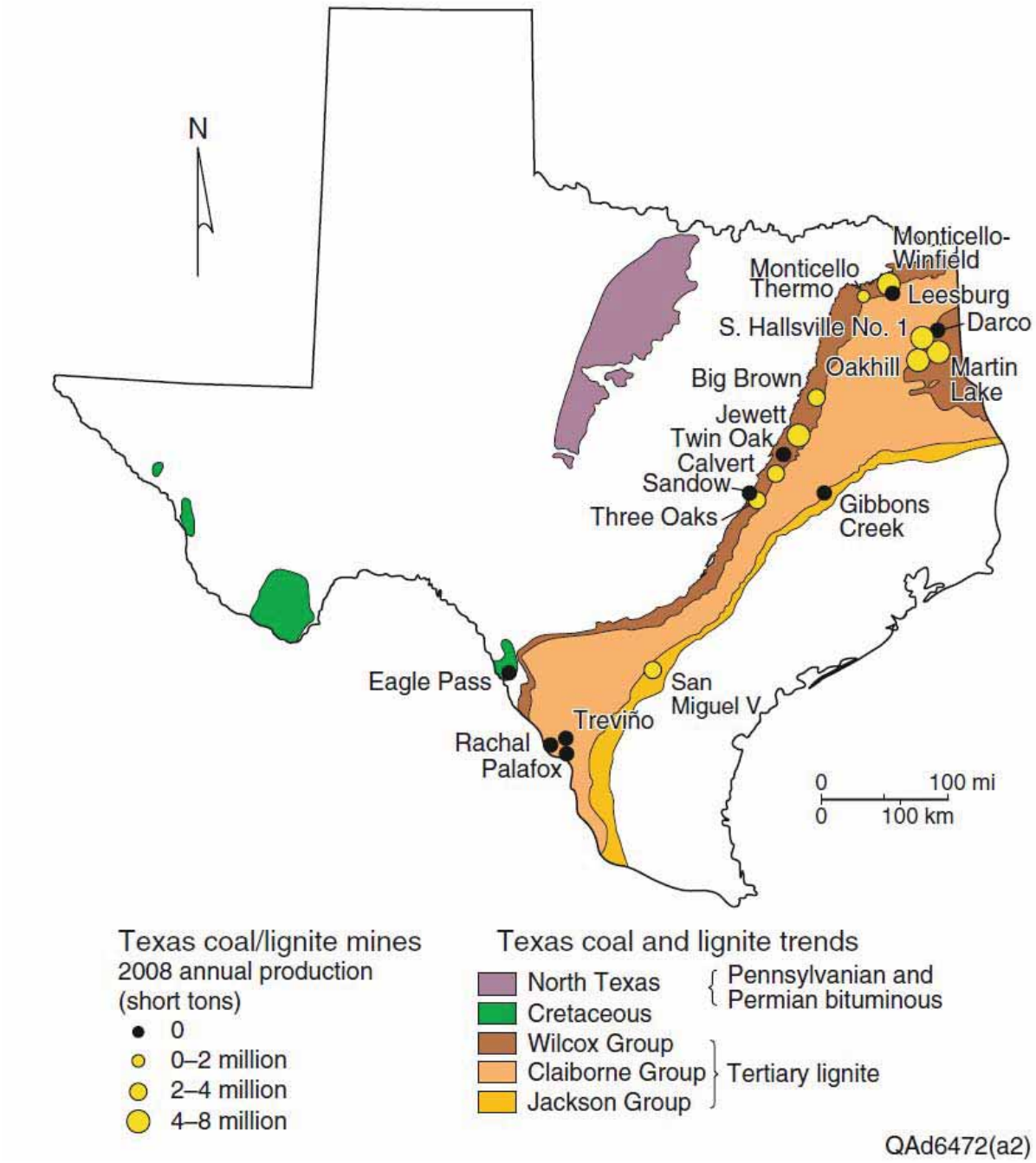
Name	County	Dewatering	Depress.	Other	Use
Monticello Thermo	Hopkins	77.7% overburden	0%	22.3% water supply	95% dust suppression 5% washing
Monticello Winfield	Titus	0%	0%	100% water supply	95% dust suppression 5% washing
Hallsville	Harrison	99.9% pit	0%	0.1% water supply	
Oak Hill	Rusk	54% overburden	0%	46% water supply	95% dust suppression 5% washing
Martin Lake	Panola	12.9% overburden	0%	87.1% water supply	95% dust suppression 5% washing
Big Brown	Freestone	92.5% overburden	3%	4.5% water supply	95% dust suppression 5% washing
Jewett	Freestone/ Leon	98% but mostly overburden dewatering		2% water supply	
Calvert	Robertson	2% overbrd. 2% pit	95%	1% water supply	Mine operations + discharge
Sandow	*Milam*		*100%*		
Three Oaks	Bastrop/ Lee		99%	1% water supply	
San Miguel	Atascosa/ McMullen	2% pit	98%	unknown	Discharge to Class V injection wells

Table 27. Water source for current lignite operations in Texas

Name	County	Fresh	Brackish	GW	SW
Monticello Thermo	Hopkins	100%	0%	80%	20% (water rights)
Monticello Winfield	Titus	100%	0%	50%	50%
Hallsville	Harrison	100%	0%		100% pit dewatering but also seepage (GW)
Oak Hill	Rusk	100%	0%	58.5%	41.5% (water rights)
Martin Lake	Panola	100%	0%	100%	0%
Big Brown	Freestone	100%	0%	100%	0%
Jewett	Freestone/ Leon	95%	5%	Unknown	Assumed all GW
Calvert	Robertson	100%	0%	100%	
Sandow	*Milam*	*100%*	*0%*		
Three Oaks	Bastrop/ Lee	100%	0%	100%	0%
San Miguel	Atascosa/ McMullen	0%	0%	100% saline	0%

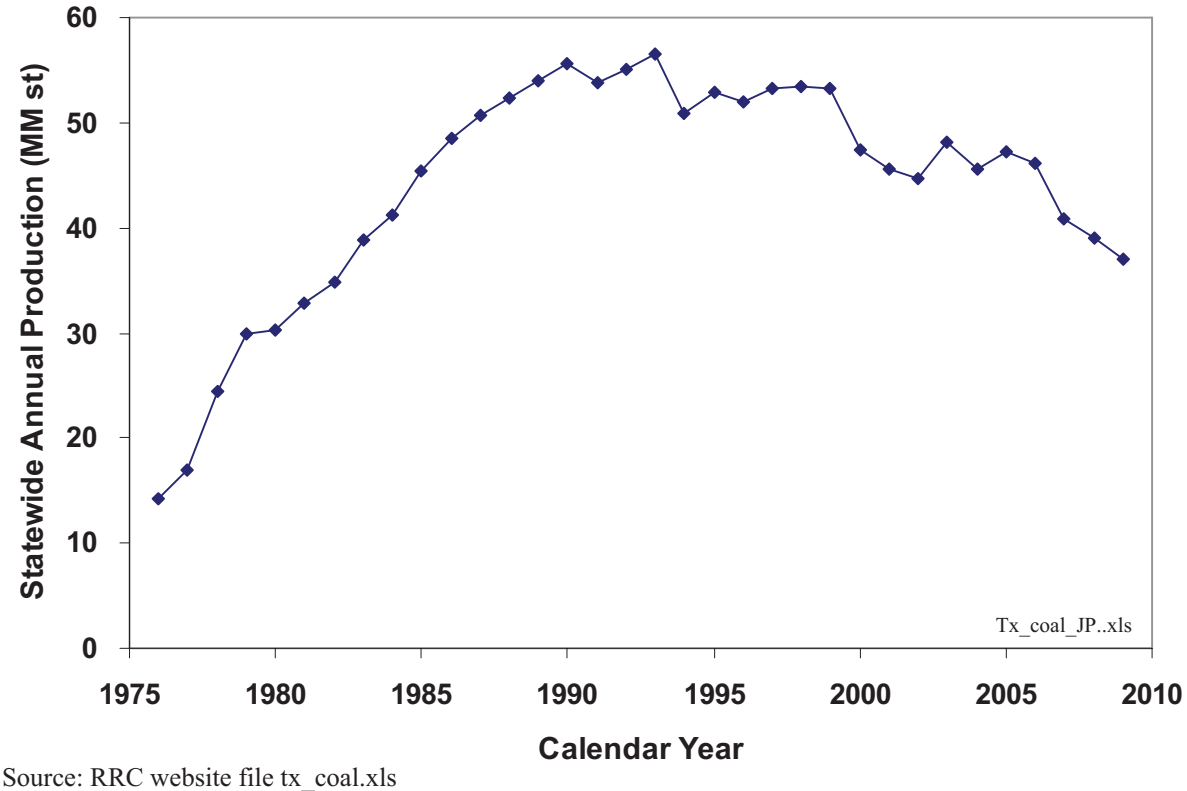
Table 28. Estimated lignite mine water use per county in AF/yr (2010)

Contributing Mine	County	Total Pumpage	Total Consumption	Pumpage Groundwater	Consumption Groundwater	Pumpage Surface Water	Consumption Surface Water	Pumpage Fresh Water	Consumption Fresh Water
San Miguel	Atascosa	0	0	0	0	0	0	0	0
1/2 Three Oaks	Bastrop	2,089	21	2,089	21	0	0	2,089	21
Big Brown, 1/3 Jewett	Freestone	3,129	124	3,129	124	0	0	3,095	124
South Hallsville	Harrison	5,800	6	6	6	5,794	0	5,800	6
Monticello Thermo	Hopkins	920	205	735	21	185	185	920	205
1/2 Three Oaks	Lee	2,089	21	2,089	21	0	0	2,089	21
1/3 Jewett	Leon	667	13	667	13	0	0	633	13
1/3 Jewett, Kosse Strip	Limestone	694	41	694	41	0	0	661	41
Martin Lake	Panola	982	855	554	428	428	428	982	855
Calvert, Twin Oak	Robertson	7,436	74	7,436	74	0	0	7,436	74
Oak Hill	Rusk	1,265	582	741	58	524	524	1,265	582
Monticello Winfield	Titus	619	619	310	310	310	310	619	619
TOTAL		**25,689**	**2,562**	**18,449**	**1,116**	**7,240**	**1,446**	**25,589**	**2,562**



Source: Ambrose et al. (2010)

Figure 97. Distribution of Texas lignite and bituminous coal deposits, coal mines currently permitted by the RRC with 2008 annual production in short tons



Source: RRC website file tx_coal.xls

Figure 98. Statewide coal/lignite annual production (1975–2009)

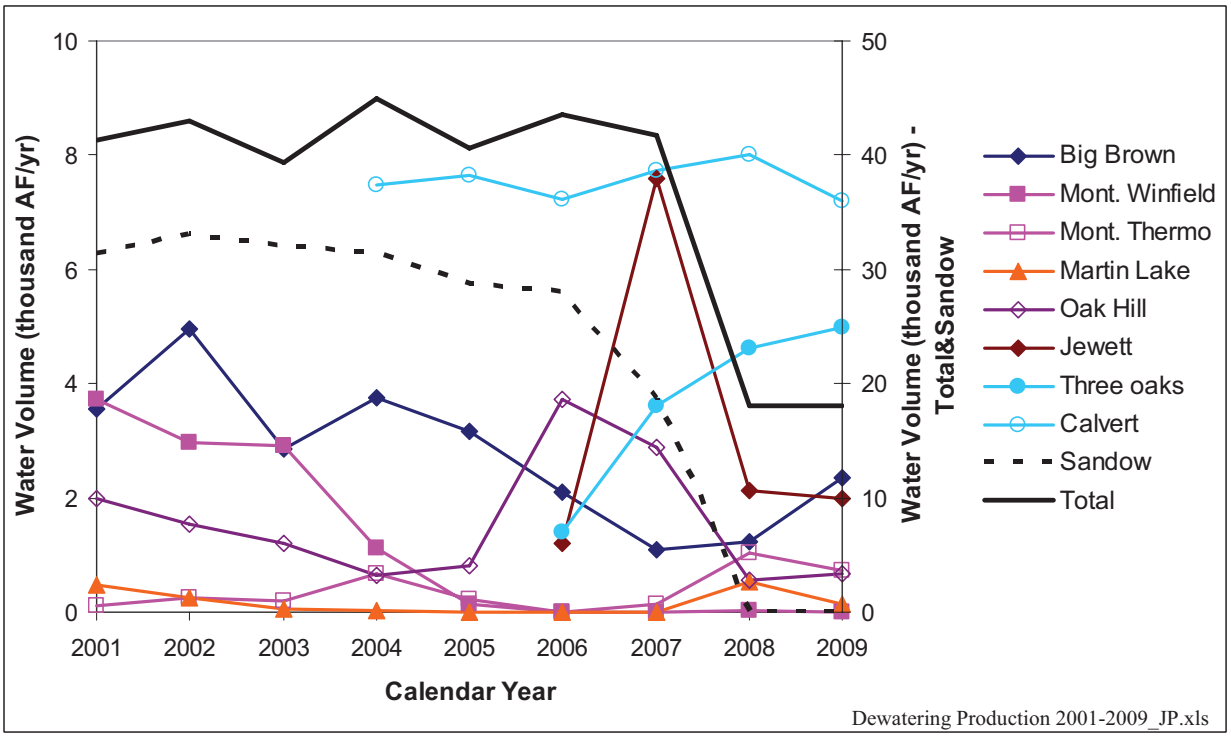
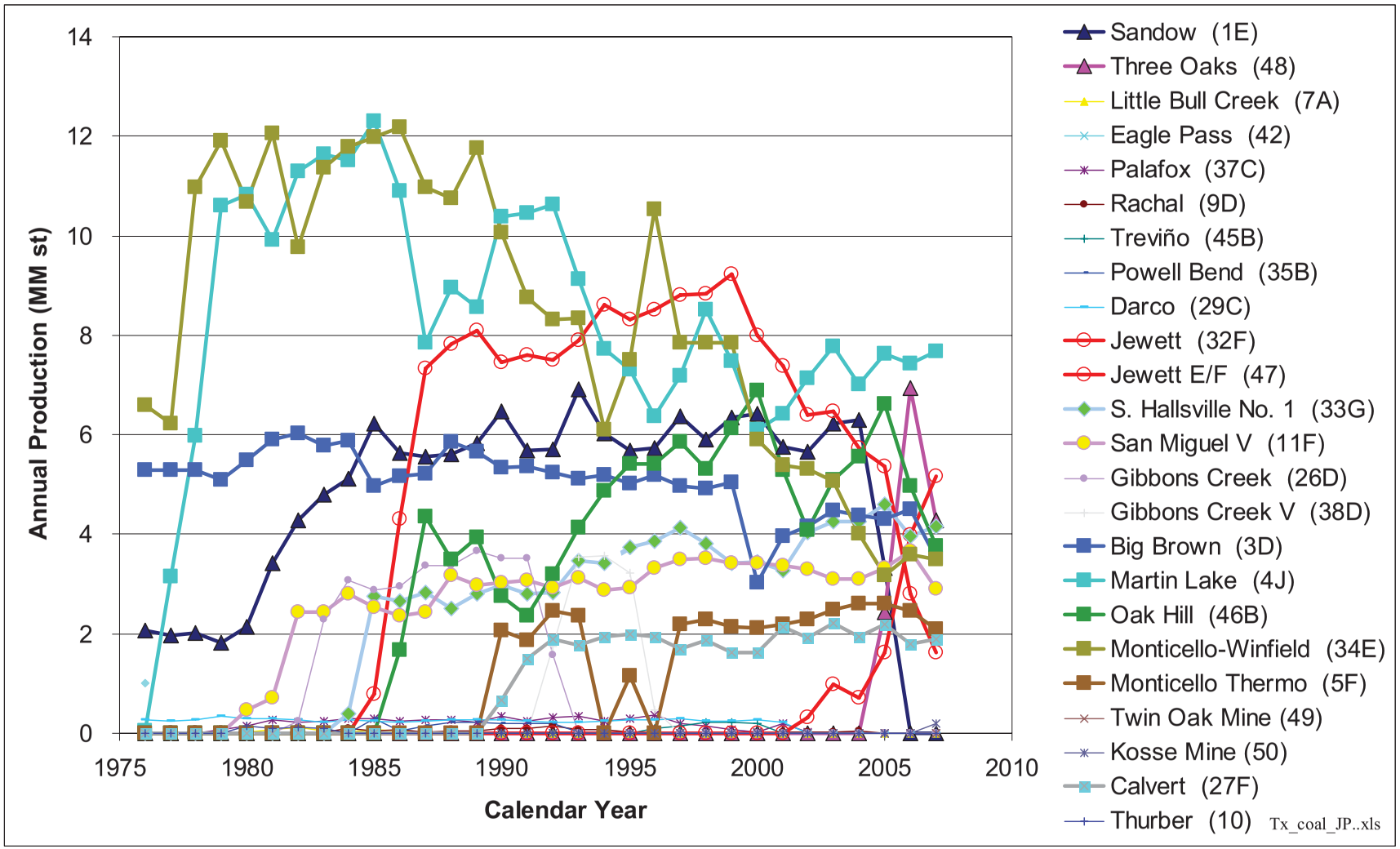


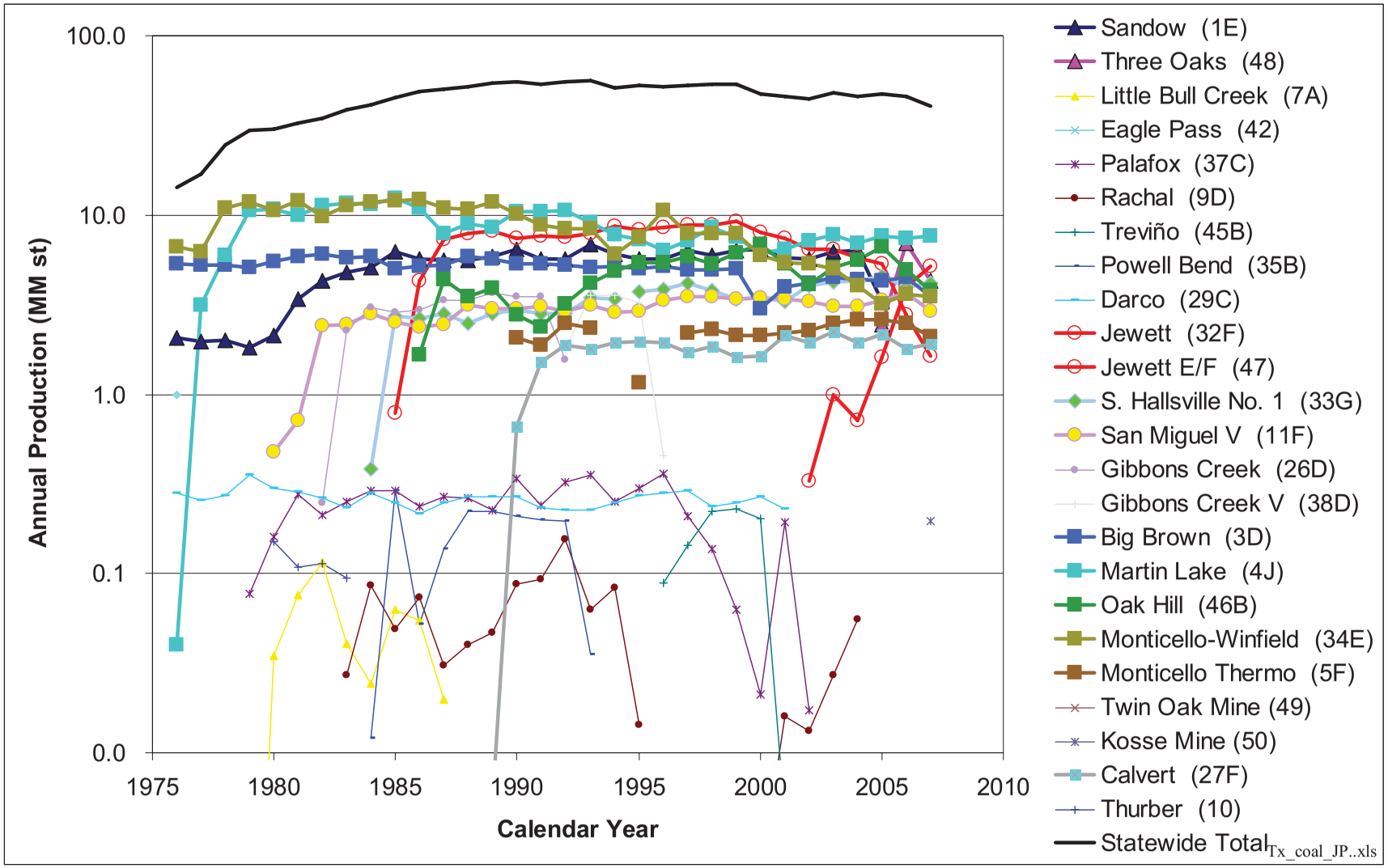
Figure 99. Lignite mine groundwater production 2001–2009



(a) linear scale

Note: permit numbers in brackets

Figure 100. Production of Texas coal mines (1976–2007)



(b) log scale

Source: RRC website file tx_coal.xls

Figure 100. Production of Texas coal mines (1976–2007) (continued)

4.4 Aggregates

This section summarizes work presented in Walden and Baier (2010) that addresses nonfuel industrial mineral mining, including aggregates, stone, clays, metals, and nonmetallic minerals. Most of the information focuses on crushed stone and construction sand and gravel, which make up the largest portion of the industrial mineral mining industry in Texas and constitute one of the greatest water users. As detailed in the methodology section (Section 3.3.3), the current TWDB data set is used as a basis and is compared with the newer BEG survey. In Section 4.4, we describe our efforts to bring in additional information, particularly confirmation of water-use coefficients.

4.4.1 General Aggregate Distribution

Aggregates fall into two major categories: crushed stone and sand and gravel, as well as a miscellaneous third category. Having a low value on a mass basis, aggregates tend to concentrate around urban areas because transportation costs can be prohibitive unless they possess an intrinsically higher value such as industrial sand (used in hydraulic fracturing) or igneous crushed stones (Figure 101). Aggregate products can be economically trucked up to 50 miles and can be shipped by rail up to 200–250 miles.

Carbonates (limestone and dolomites) for crushed rock exist in large quantities across most of the state but typically come from selected formations such as the Edwards Limestone (Garner, 1994), especially along the Balcones Fault Zone (west of San Antonio to south of Dallas). Overall, crushed stone consists mostly of limestones but also sandstones, as well as granitic rocks in the Llano area and volcanic rocks ("trap rock") in the Uvalde area. Carbonates, and more generally crushed stones, have several purposes, including concrete making, ballast, base material under foundations, roads, and railroads, but also manufacture of cement and lime. Sand and gravel facilities are located mainly along streams and rivers and in the Gulf Coastal Plains and tend to be smaller and sometimes intermittent.

Some facilities are located below the water table and need to pump seeping groundwater (as well as stormwater) from the exploitation pit. It is difficult to estimate the amount of groundwater (which should be counted toward withdrawal) relative to the amount of stormwater (which should not be counted as either groundwater or surface-water withdrawal) without undertaking a study of the local hydrologic system, unless a water-source breakdown is provided by the operator.

4.4.2 Description of Mining Processes

4.4.2.1 Crushed Limestone Mining

Hard-rock limestone is mined by blasting large sections of the quarry wall and extracting the shot rock with excavators, loaders, or other mechanical equipment. Large dump trucks transport the material to rock crushers, where it is reduced to a size that can be moved by conveyor belts to other parts of the operation. No water is used during extraction except for roadway watering and dust suppression, as needed. Initial rock crushing and separation are also performed dry except for dust suppression. Road-base products, which contain higher proportions of clay and pit fines, are produced in this dry section of the plant. Harder rock is passed sequentially through a series of crushers, shakers, and screens with a multistage washing system to produce a variety of product sizes. Amount of water used depends on how dirty the rock is and the number of products to be generated. Different sized products are separated and stockpiled for delivery to

customers. Products can be mixed in various proportions to satisfy specific customer specifications. The wash water removes very fine particles and impurities from the larger aggregate products. These small particles are further separated from the wash water using cyclones, rotating screws, weirs, and fine screens to produce manufactured sand. Figure 102 represents a simple flow diagram of a typical crushed-stone mining process.

The remaining water is captured and typically routed to large settling ponds to allow super-fine particles of silt and clay to settle out of suspension before being pumped back to supply ponds to be recycled for reuse in the process. Smaller operations or quarries with limited available space may use closed filtration or similar equipment to further clean and recycle wash water. Discharge of water is rare and generally only occurs during seasonal, heavy rainfall events that overwhelm the retention ponds. As a result of the active water recycling and reuse efforts in place at most crushed-stone quarries, only ~20 to 30 percent of the water used in the operation is actually consumed and must be replaced. Water loss generally results in four ways: (1) retention of water in the moisture content of final product shipped to customers; (2) application of water on roadways, conveyor belts, and transfer points to suppress dust; (3) spillage and absorption of water from washing process equipment and pipes; and (4) evaporation from ponds and open equipment.

Rainwater, spillage, and drainage from stockpiles are collected and routed to settling ponds or other equipment to reduce the amount of makeup water required. Surface ponds that are below the local water table may also have significant groundwater seepage into the ponds. In some areas of the state, this seepage is often enough that active pumping from groundwater or surface-water sources is not required or may only be necessary during summer months or periods of extreme drought. Brackish or saline water cannot be used for aggregate mining because the salt will adversely impact the quality of the concrete, asphalt, and other products manufactured from the materials.

4.4.2.2 Sand and Gravel Mining

In open-pit sand and gravel mining, material is removed using excavators, front-end loaders, draglines, or shovels and transported by trucks for processing. Deposits are frequently located near streams or waterways and are mined moist. No water is required for extraction and, in some cases, water must be pumped away from the mining site to allow access by machinery, although some facilities with deposits below the water table use dredges. Dewatering of groundwater seeping into the mining site is often used as wash water but may also need to be supplemented by groundwater and surface-water sources.

In most dredge-type sand and gravel mining, materials are pumped from the bottom of a body of water and piped to the processing plant in a high volume of water. The sand and gravel are separated, and the bulk of the water is returned to the original location. This return water is critical to maintaining an adequate volume of water at the mine site to allow continued pumping. Some dredge mines use bucket dredges to load material onto barges or other means of transport to processing locations.

Sand and gravel are processed through a series of shakers, screens, and washers to size, separate, and clean different products. Larger rocks may be crushed or removed for other uses. Rotating screens with water sprays are used initially to treat wet materials before log washers or rotary scrubbers remove clays and organic materials. Screening is used to separate product by size. Products are dewatered with screw conveyors, cyclones, or other separators and then transported

to stockpiles. Wash water is routed to stormwater retention ponds, where particles are allowed to settle out. It is then recycled as process water or applied on plant roadways for dust suppression, as needed. Because sand and gravel are typically wet, little if any water is required on conveyors or other equipment for dust suppression. The moisture content of sand and gravel can be ~5% to 6%, resulting in proportional loss of water.

4.4.3 External Data Sets

Several databases (MSHA, USCB) list aggregate facilities and related commodities but do not include information on their production (Table 2, Table 3). A trade association (NSSGA) in association with USGS also reports names and locations of aggregate facilities but, similar to USCB and MSHA, does not provide commodity production or water use. As described next, we investigated with little success the possibility that TCEQ own information about water use. TCEQ regulates surface-water rights. We also conducted a survey of GCDs to access information on groundwater use.

4.4.3.1 TCEQ Central Registry

TCEQ is responsible for the regulation and permitting of all sources of air and water pollution and has adopted rules that specify the control technologies and emissions limits that must be met by industries, including mining operations, in Texas. The TCEQ has established a Central Registry of all regulated entities, which contains information about the companies and specific locations of industrial sites. Each regulated site is issued a Registration Number or RN Number, which allows the agency and the public to readily access this information and links to other program records related to permitting, compliance, inspections, enforcement, and other actions taken by the TCEQ. The Central Registry database was queried to extract information on all active facilities with major, two-digit SIC Codes of 10, regarding metal mining, and 14, regarding mining and quarrying of nonmetallic minerals, except fuels. The numbers and types of facilities identified by this search were far larger than identified by MSHA and NCCGA and are shown in Table 29.

4.4.3.2 TCEQ Surface-Water Diversion

The TCEQ issues and regulates water-rights permits and withdrawals of most surface water in Texas including navigable waters, reservoirs, and major impoundments. Each water right holder must submit monthly reports indicating the amount of water diverted, amount returned, and the amount consumed. The TCEQ provided spreadsheet data on water-rights reports from entities identifying themselves as mining users for 2006–2008. The agency was unable to segregate the mineral-mining facilities from other mining interests, such as oil and gas or coal, so it was difficult to clearly differentiate the available data. Many of the companies that were clearly recognizable as mineral mining reported no surface-water diversions, or they indicated that they consumed 100 percent of the amount that they did divert. In some cases, companies did report significant return-flow quantities. However, there appeared to be some confusion on the appropriate reporting requirements because some companies reported that the sum of the amount returned and consumed exceeded the amount that was diverted throughout the year. Appendix F includes a table that provides all of the active water-rights holders in the mining industry, along with the amount of water they are authorized to withdraw in acre-feet per year. It also includes a table of the 2008 Water Rights Reporting Data.

Further evaluation of the TCEQ Water Rights data to identify and extract industrial mineral mining information and to resolve gaps and inconsistencies in the reported values may be

worthwhile. However, most mineral mining operations do not depend on surface-water-rights diversions except to supplement captured stormwater and recycled water when needed.

The TCEQ does not regulate the extraction of groundwater. Local GCDs have been established to monitor and control the amount of water withdrawn from aquifers in many areas of the state. No centralized data are available for specific types of water use, and additional investigation would be required to survey GCDs to determine whether they maintain data on mining activities within their jurisdiction. Information gathered from GCDs is posted in Appendix E.

4.4.3.3 TCEQ TPDES

The TCEQ regulates wastewater from major industrial and commercial sources under the Texas Pollution Discharge Elimination System (TPDES) through permits that control the amount and quality of effluent discharged. Discharge of process water requires an individual, site-specific permit, whereas discharge of stormwater can often be authorized under the Multi-Sector General Permit (MSGP) for major industrial activities. All of the SIC code categories for mineral mining operations (major two-digit Groups 10 and 14) are subject to the MSGP. Facilities are required to monitor and report the quantity of discharges but do not need to report captured or recycled water if it does not leave their property. Because most mining operations actively recycle much of their water, they only discharge during periods of exceptionally heavy rain. Examination of individual TPDES permits and discharge-monitoring reports will be of limited value in quantifying water use or consumption.

The TCEQ regulates the emission of air pollutants to reduce or avoid the release of contaminants that could adversely affect public health or the environment. Mineral mining operations have the potential to emit particulate matter (PM) from a number of processes that require controls to be implemented. Rules and air-quality permit requirements most often direct mining operations to reduce these PM emissions by applying water sprays to crushers, conveyors, transfer points, stockpiles, and roadways to suppress dust. This application becomes a major source of water consumption because most or all of the water used for these purposes evaporates. TCEQ rules do not require sources to monitor or report the amount or frequency of water used for particulate controls. Although some facilities record some related activities, such as the number or frequency of water trucks used to spray roadways, for their own management needs, such data are not consistent and cannot be reliably used. Further evaluation of air permits or controls will have limited value in quantifying the amount of water used or consumed by the mining industry.

4.4.3.4 TCEQ SWAP Database

The federally mandated TCEQ Source Water Protection (SWAP) project database contains a wealth of information about current and past mining activities and is a good source to locate facilities. However, it does not provide information about water use.

4.4.4 BEG Survey Results

4.4.4.1 Survey of Facilities

Results of the BEG survey are summarized in Table 30 (without reference to specific facilities or their location). Total production for crushed stone from the surveyed facilities translates into ~35 million tons, or 22.5 % of state total production, and may be sufficient to imply some validity and predictive power to this aggregate category. On the other hand, sand and gravel survey results add up to only ~3.6 million tons, or 3.6% of the state total production, and thus provide more limited predictive power. Overall surveyed facilities are well distributed across the state

and are located in areas where most of the population resides (Figure 103). The 26 facilities (18 crushed stone and 8 sand and gravel) show a large range in terms of production (<0.2 to >13 million tons per year), reported gross water use (a few AF/yr to >4,000 AF/yr), reported net water use (a few AF to >2,000 AF/yr), and in a category called groundwater and surface-water net water use (from 0 to >1,000 AF/yr). The last category does not consider stormwater in net water use and account only for so-called external sources (surface water or groundwater). Plotting the information (Figure 104) graphically illustrates the relationship between these types of water use.

The stormwater category is included because precipitation falling on the property is generally redirected to sumps and ponds to comply with TCEQ regulations. Often that stored stormwater alone can be sufficient to run aggregate operations. This study did not try to determine whether the drainage area and precipitation at a specific facility are consistent with the amount of stormwater reported to be used. Such a task goes beyond the scope of work, although data to perform it are readily available. Discriminating between stormwater and groundwater is difficult in a pit whose bottom might be deeper than the water table, but it is just as conceivable to think that the stored stormwater recharges the aquifer as to think the reverse.

Water-use statistics are computed with and without accounting for stormwater (Table 31): the crushed-stone water-use coefficient is either 64 gal/st (with all water sources) or 36 gal/st (without counting stormwater), and sand and gravel water-use coefficient is either 68 gal/t (all water sources) or 47 gal/st (without storm water). Excluding dry process facilities and facilities from a company that seems to have much lower water-use coefficients produces 151 and 66 gal/st for wet process and crushed stone facilities, respectively. However, we think that the fraction of dry vs. wet process facilities is representative of the state as a whole (because we obtained complete data from a large operator in the state) and that lower water-coefficient facilities should also be included in the average (because they come from several large facilities). Recall that in the methodology section we explained that averages were made on a production basis not as a simple average of each facility average.

The amount of reported recycling varies widely from none for dry-process crushed-stone facilities, which only consumes water for dust suppression and a few wet-process crushed-stone facilities, possibly because they have stormwater in excess, to almost 100% in some highly water-conscious facilities. A few wet-process crushed stone facilities also reported no recycling, possibly because they have excess storm water available or because they misinterpreted the question. Most facility recycling rates range from 65% to 90%. For the washed crushed-stone mining operations that reported recycling, rates were in the expected range of from 49% to 86%. Recycling at surveyed sand and gravel operations was reported at rates ranging from 74% to 99%.

Unexpectedly, five operations indicated that no recycling of water was conducted at the mines and that all of the gross water used was consumed. This may be due to a misunderstanding of the survey questionnaire rather than an unrealistic indication that all water is used only once at the facility and is lost to product or evaporation. A more probably interpretation is that no exceptional recycling activities have been implemented to increase water reuse. In these cases, the reported amounts should be considered net water use. This study focuses on the net water use and did not need knowledge of gross water use or recycling rate because, unlike oil and gas activities, recycling serves only one single facility. The large spread in net water use is illustrated in Figure 105, which displays histograms of water consumption. However, values cluster ~0 to

30 gal/t for dust control (roads and machinery) and show a bimodal distribution at <20 gal/t and ~50 gal/t for washing. Both distributions have very long tails. Gross-washing water use reportedly ranges from a minimum of 3.0 gpm/tph for very clean rock (rare) up to 15.0 gpm/tph for dirty rock (as sometimes seen in the Edwards Limestone), that is, 180 to 900 gal/t (Walden and Baier, 2010).

The source of consumed water (Table 32) is equally difficult to generalize because of the limited size of the analyzed sample, but it seems that on average more than half of the consumed water is groundwater. This figure, however, represents an average that matches only a few facilities (Table 30). Water for most operations come from only one of three possible sources (groundwater, surface water, or stormwater). It is thus impossible to attribute water source at a county level without specific knowledge of the water use at each facility.

4.4.4.2 Survey of GCDs

Survey results are described in detail in Appendices D and E and integrated within the body of the report. Overall, except for a few very responsive districts, most GCDs either did not respond to the survey or did not have access to the requested information. In summary, findings indicate that most groundwater conservation districts do not collect estimates of groundwater use by mining operations. The districts generally rely on information reported by the TWDB, even though they may not be able to confirm the information. Fewer than 50 percent of the districts surveyed replied with any information. Of the respondents, only 20 percent provided any quantitative volumetric estimate of use or permitted use of groundwater by mining entities. No districts reported having monitoring systems in place to measure groundwater use that was permitted for mining. Therefore, other than the reported current use data in Appendix D (Table 72), the districts were unable to provide better projections of water use by mining.

4.4.5 Historical and Current Aggregate Water Use

Table 33 summarizes some historical water-use coefficients, a parameter not easy to come by as discussed earlier. Old reports (for example, Quan, 1988, published by the Bureau of Mines) mention ~300 gal/st but variable across the years (470 to 220) (his Fig. 30) and probably across the country as well as a function of local conditions. About half is recycled water (Quan, 1988, Table 5). Crushed stone intensity of water use ranges from 60 to 150 gal/st (his Fig. 34). Quan (1988) presented data for 7 individual years between 1954 and 1984. The trend is towards reduction in water use but not in a regular fashion and actually shows an uptick in the last year (1984), amount of recirculated/recycled water increased from a small fraction in 1954 to 50% in 1984. Quan (1988, p.32) estimating future water use in 2000 for the U.S. Bureau of Mines also relied on intensity of use coefficients using them as multipliers to the projected mineral production. Norvell (2009, Table 3) calibrated USGS water-use coefficients from Quan (1988) to Texas water-use surveys done ca. 2000. He doubled water-use relative to the U.S. average and assumed 80% recycling. Mavis (2003, Table 6.1–2) provided figures in the following subcategories for the sand and gravel category: 1–6 gal/t for dust control of machinery (this is consumed), 60–180 gal/t for wet screening, ~60 gal/t for sand screw, and ~90 gal/t for gravity classifier. The last three categories are for gross water use.

Recent WUS surveys conducted by the TWDB have a small overlap with the BEG survey (Table 34) in terms of facility, with an approximate agreement in terms of net water use. TWDB results cannot be used to develop water-use coefficients because production values are not provided, but they were integrated into their specific counties, as described in the methodology section.

Overall, **~24,700 AF and ~18,300 AF (total of 43,000 AF)** was consumed across the state for aggregate production. Results for individual counties are listed in Table 35.

Table 29. TCEQ Central Registry records of mining facilities in Texas

SIC Code	Type of Mine	No. of Mines	SIC Code	Type of Mine	No. of Mines
Major Group 10: Metal Mining					
1011	Iron Ore	4	1081	Metal Mining Services	8
1044	Silver Ore	6	1094	Uranium–Radium–Vanadium Ore	52
1061	Ferroalloy Ore (except Vanadium)	4	1099	Misc. Metal Ore	18
Major Group 14: Mining and Quarrying of Nonmetallic Minerals, Except Fuels					
1411	Dimension Stone	118	1446	Industrial Sand	74
1422	Crushed and Broken Limestone	1285	1455	Kaolin and Ball Clay	14
1423	Crushed and Broken Granite	8	1459	Clay, Ceramic, and Refractory Minerals (not elsewhere classified)	
1429	Crushed and Broken Stone (not elsewhere classified)	296	1474	Potash, Soda, and Borate Minerals	8
1442	Construction Sand and Gravel	1041	1479	Chemical and Fertilizer Mineral Mining (not elsewhere classified)	60
			1481	Nonmetallic Minerals Services, Except Fuels	29
			1499	Misc. Nonmetallic Minerals, Except Fuels	100

Table 30. Water-use survey results from selected aggregate operations

Production (Mt/yr)	Gross Water Use (1000s AF/yr)	Net Water Use (1000s AF/yr)	GW &SW Net Use (1000s AF/yr)	Water Use (gal/st)	Recycle Rate (%)	Source Water		
						GW	SW	StW
Crushed stone (wet process)								
4.00	4.1	1.3	0.00	107	68%			100%
1.76	2.9	0.5	0.54	100	81%	100%		
0.80	1.1	1.1	1.10	450	0%	100%		
1.33	1.6	0.4	0.41	100	75%	100%		
0.85	1.2	0.2	0.09	65	86%		50%	50%
1.50	1.4	1.4	0.00	300	0%			100%
*0.20**	0.2	0.2	0.15	*est 250*	0%		100%	
*0.65**	0.1	0.1	0.03	*est 250*	0%	55%		45%
*0.18**	0.3	0.1	0.04	*est 250*	52%	30%		70%
*0.33**	0.3	0.3	0.00	*est 250*	0%			100%
3.50	1.1	0.3	0.33	31	70%	100%		
13.70	4.3	1.1	1.06	25	75%	100%		
0.60	1.1	0.2	0.14	92	84%	80%		20%

Production (Mt/yr)	Gross Water Use (1000s AF/yr)	Net Water Use (1000s AF/yr)	GW &SW Net Use (1000s AF/yr)	Water Use (gal/st)	Recycle Rate (%)	Source Water		
						GW	SW	StW
Crushed stone (dry process)								
0.29	0.01	0.01	0.01	9	0%	100%		
0.39	0.01	0.01	0.00	10	0%			100%
4.56	0.14	0.14	0.14	10	0%	100%		
2.28	0.07	0.07	0.00	10	0%			100%
5.00	0.02	0.02	0.02	2	0%	18%	82%	
Sand and gravel								
0.55	0.29	0.08	0.08	45	74%		100%	
0.52	0.12	0.04	0.04	26	67%		100%	
0.21	0.12	0.03	0.00	38	79%			100%
0.50	1.84	0.03	0.03	18	99%		100%	
0.50	2.00	0.35	0.35	228	83%	100%		
0.30	0.09	0.02	0.02	22	76%	100%		
0.52				0	Y			100%
0.48				0	Y			100%

*: estimated

Note: some facilities may underreport their stormwater use

Table 31. Aggregate net water use/consumption based on BEG survey results

	Number of Data Points - % of State Production	1000s AF /million tons	Gal/t
Crushed-stone water-consumption coefficient			
All water sources	17–22.5%	0.197	64
GW+SW only	17–22.5%	0.109	36
Wet process crushed large w/o low water-use coefficient facilities			
All water sources	10–~8%	0.465	151
GW+SW only	10–~8%	0.204	66
Sand and gravel water consumption coefficient			
All water sources	6–3.6%	0.209	68
GW+SW only	8–3.6%	0.143	47

Table 32. Net water-use breakdown by water source

		Groundwater	Surface water	Stormwater
Crushed Stone	Weighted by production	0.706	0.011	0.295
	Facility average	0.491	0.129	0.381
Sand and gravel	Weighted by production	0.689	0.291	0.020
	Facility average	0.250	0.375	0.250

Note: crushed stone survey represents ~22.5% of total production, whereas sand and gravel survey sample represents only 3.6% of production

Table 33. Historical water-use coefficients for aggregates (gal/st)

Withdrawal	Recycled	Total	Discharge	Consumption	Source
Sand and Gravel					
		220–470*			Quan (1988, Fig.30) 1954-1984
130	59	189	88	42	Quan (1988, Table C-5) 1984
260			52	208	Modified from Norvell (2009, p.13)
		211–336			Mavis (2003, Table 6.1-2)
Industrial Sands					
806	2891	3697	259	547	Quan (1988, Table C-5) 1984
1612			322	1290	Modified from Norvell (2009, p.13)
Crushed Stone					
		60–150			Quan (1988, Fig.34) 1954-1984
68	64	132	48	20	Quan (1988, Table C-5) 1984
136			27	109	Modified from Norvell (2009, p.13)

*including industrial sand

Table 34. Results from recent TWDB WUS

Sand and Gravel		Crushed Stone	
Year	Net Water Use (AF)	Year	Net Water Use (AF)
2007	72	2007*	1,058
2007	1,468	2007*	824
2005	3,020	2007*	1,196
2006	6	2007**	625**/0.9
2007	0	2002	625
2001	150	2007	4,822
2007	2	2007	1,787
2007	386	2007	185
2007	112	2007	341
2007	0	2007	0.6
2004	5	2007	0.3
2007	2,384		

*facility with water-use approximately confirmed by BEG survey
**consistent with BEG survey only for earlier years
Source: TWDB Office of Planning

Table 35. Estimated county-level crushed-stone and sand and gravel water use for 2008 (other counties are assumed to have zero water use)

County	CS	S&S	County	CS	S&S
Unit: 1000s AF					
Atascosa		0.350	Kaufman	2.063	0.195
Bastrop		0.063	Kerr		0.059
Bell	0.747	0.346	Lampasas	0.293	0.012
Bexar	3.108	1.028	Liberty		0.108
Borden		0.000	Limestone	0.210	
Bosque		0.013	Lubbock		0.415
Brazoria		0.565	Maverick	0.052	
Brazos		0.230	McLennan		1.025
Brown	0.000		Medina	0.287	0.063
Burnet	0.280	0.031	Montague	0.104	0.010
Callahan	0.131		Montgomery		0.028
Coke		0.003	Navarro		0.062
Colorado		1.540	Nolan	0.023	
Comal	3.634	0.099	Nueces		0.445
Cooke	0.818	0.026	Oldham	0.165	0.002
Coryell	0.275		Orange		0.136
Dallas		1.574	Parker	0.170	0.253
Denton		1.262	Potter	0.192	0.308
Duval		0.604	Reeves	0.014	0.008
Eastland	0.150		Sabine	0.053	
Ector	0.168		San Patricio	0.340	0.055
El Paso		0.581	Smith		0.106
Ellis	2.898		Somervell		0.386
Fannin		0.006	Starr		0.142
Fayette		0.082	Stonewall	0.019	
Floyd	0.169		Tarrant		1.093
Fort Bend		0.000	Taylor	0.000	
Galveston		0.282	Travis	0.135	0.718
Glasscock	0.095		Uvalde	0.055	
Grayson		0.041	Val Verde		0.031
Guadalupe		0.186	Victoria		0.000
Harris		2.494	Walker	0.454	
Henderson		0.115	Ward		0.016
Hidalgo	0.170	0.603	Washington		0.018
Hutchinson	0.127	0.023	Webb	0.226	0.005
Jack	0.238		Williamson	2.273	
Jefferson		0.131	Wise	1.422	0.229
Johnson	3.091	0.075	Young	0.035	
Jones		0.010	**TOTAL**	**24.7**	**18.3**

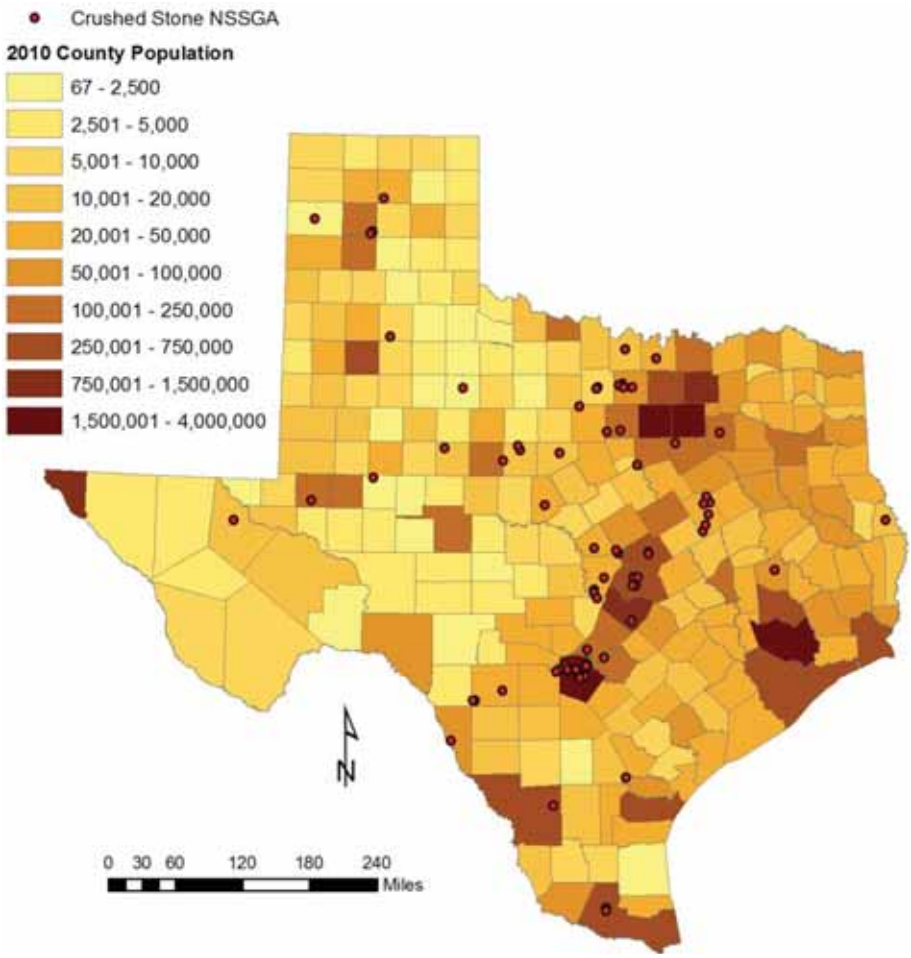


Figure 101. County population in 2010 (TWDB projection) and crushed-stone NSSGA facilities

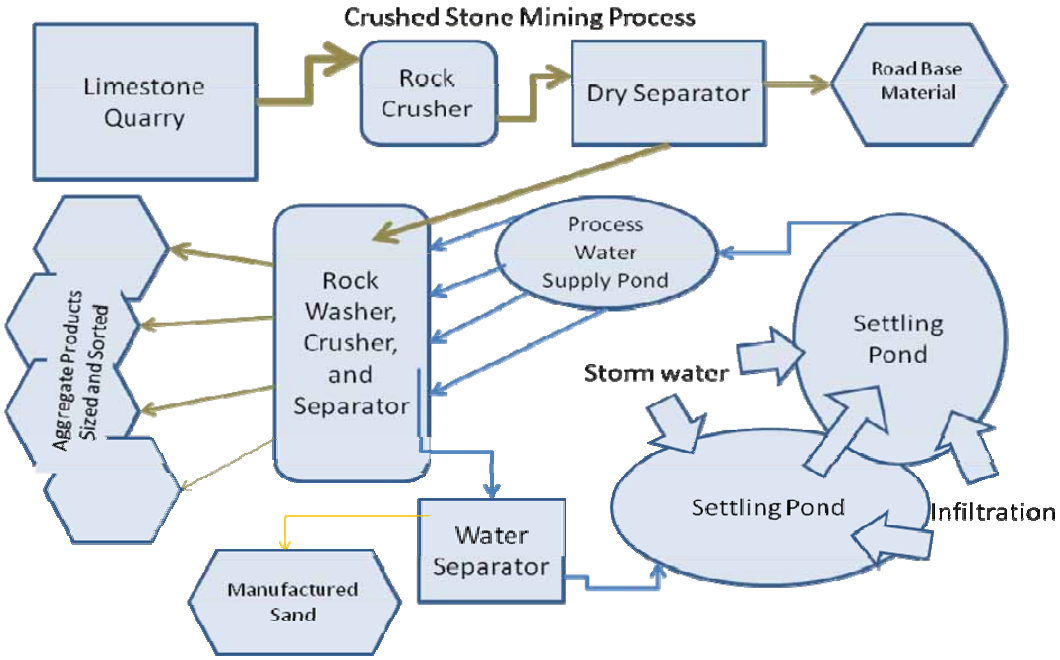
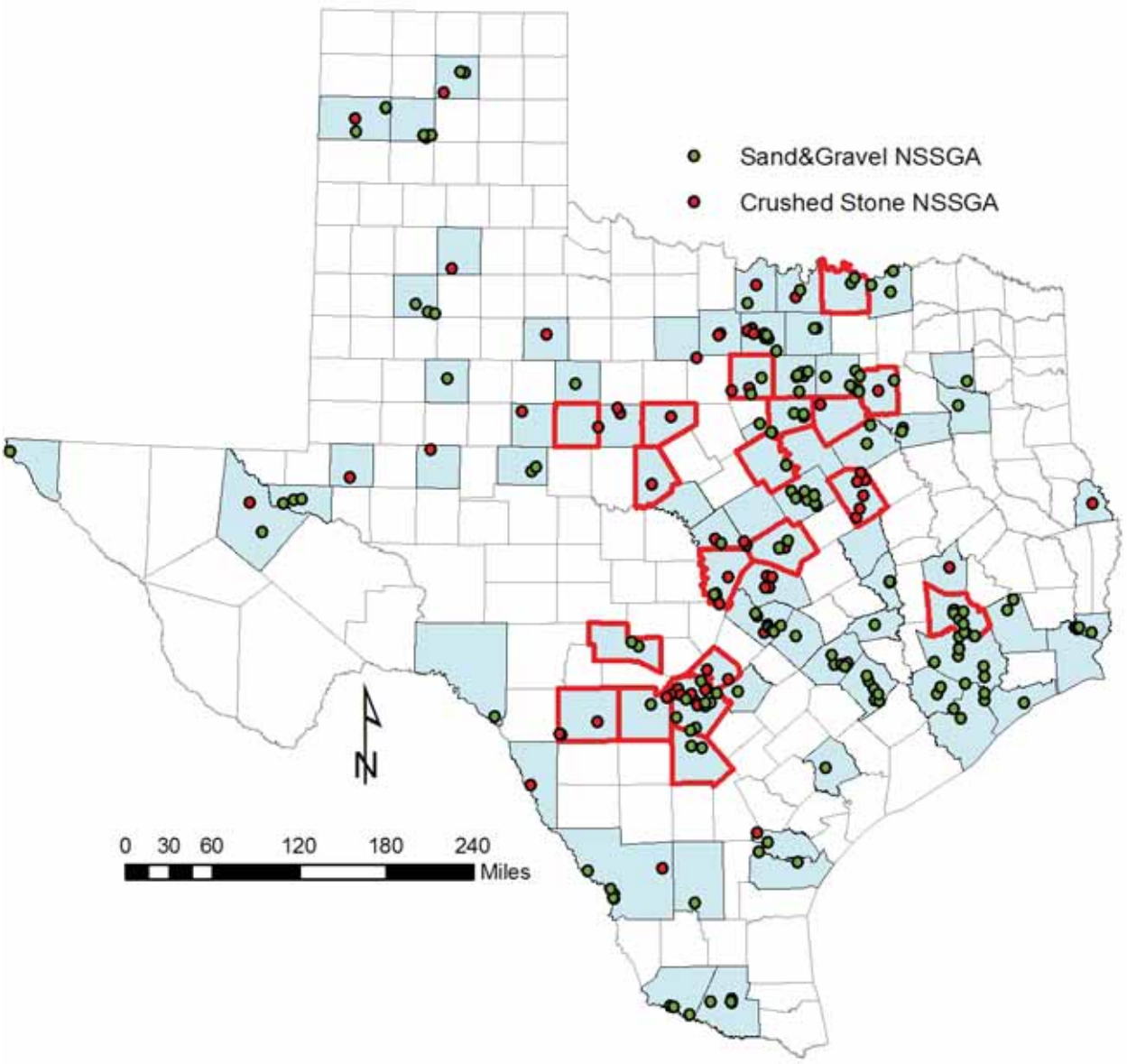
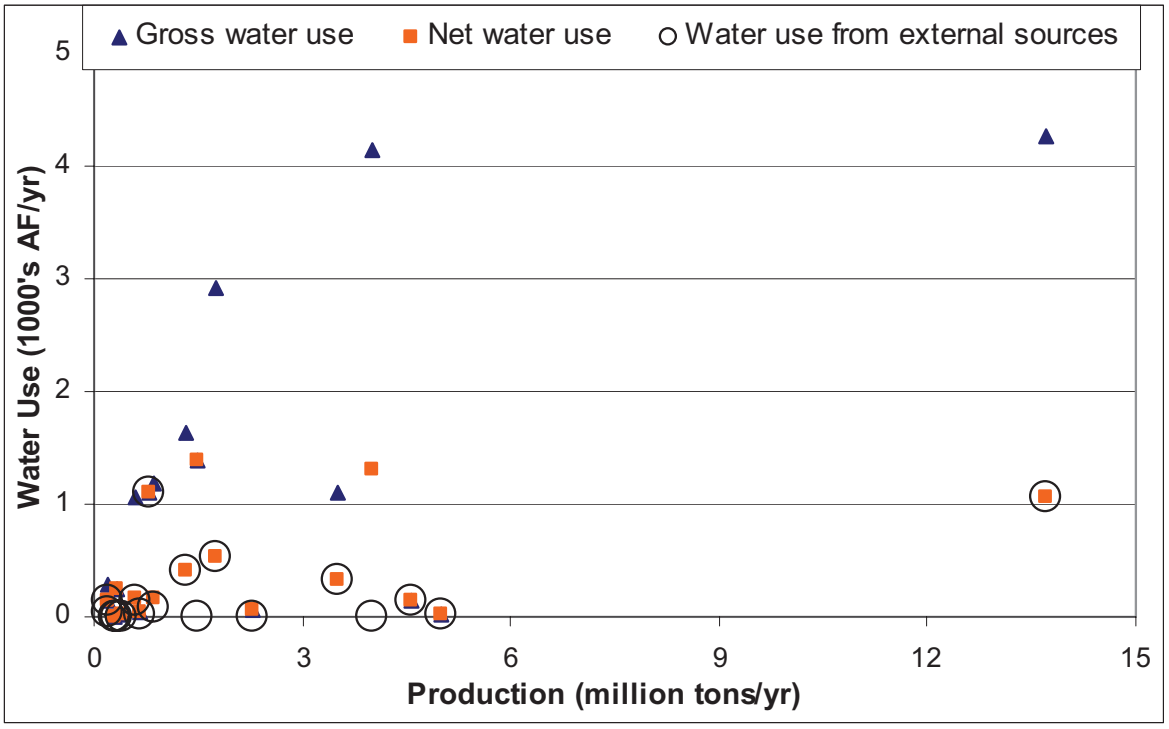


Figure 102. Flow diagram of typical crushed-stone process



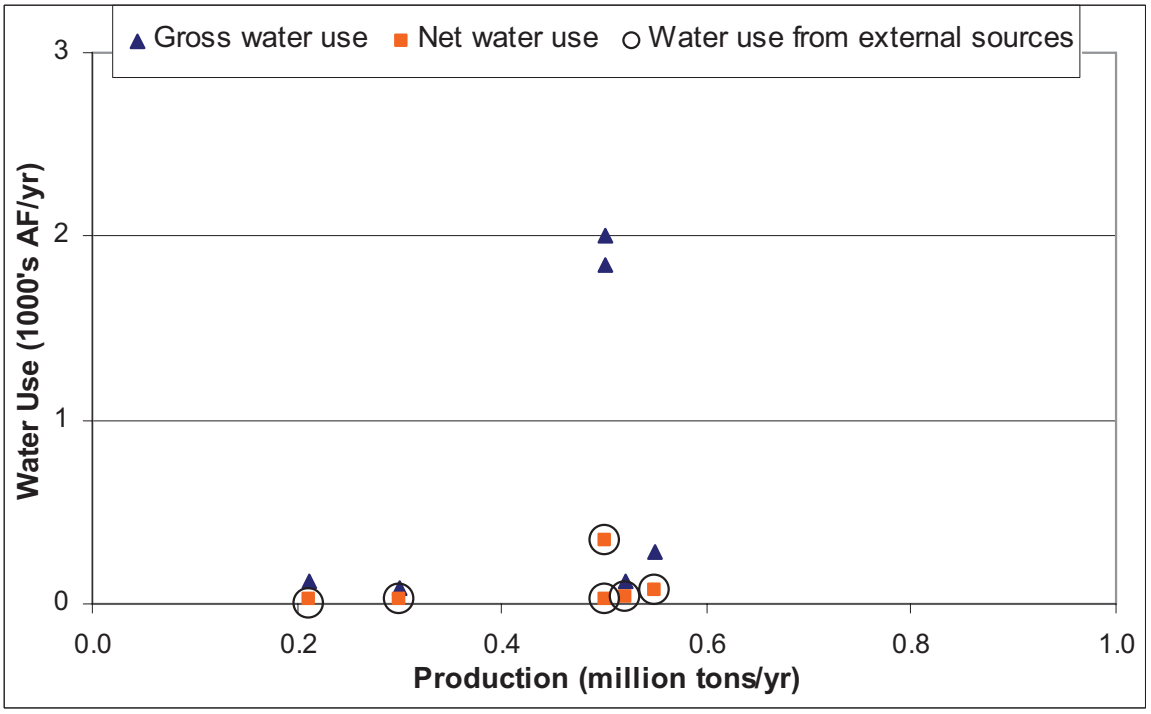
Source: NSSGA/USGS database

Figure 103. Counties with NSSGA-listed facilities; highlighted county lines represent those counties with information from the BEG survey



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

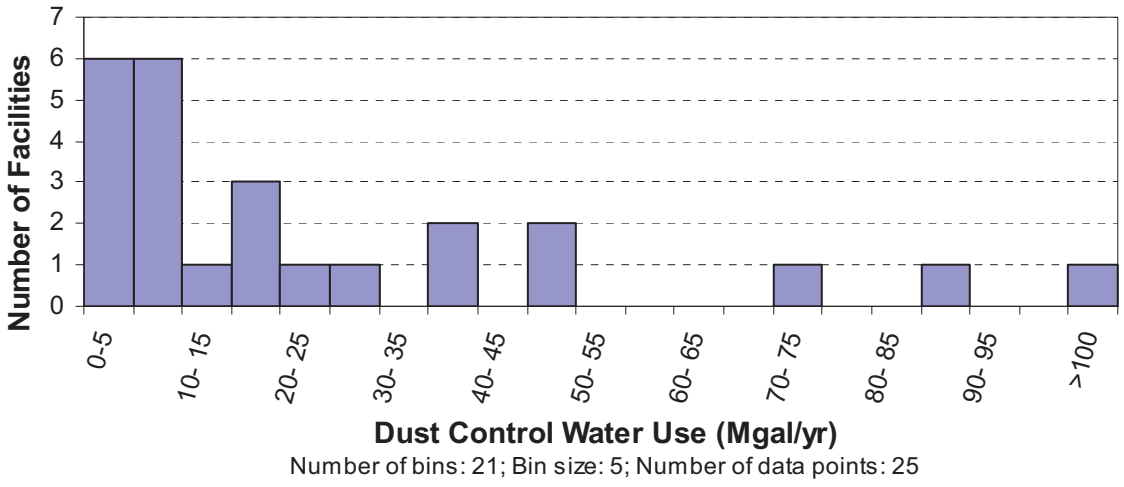
(a)



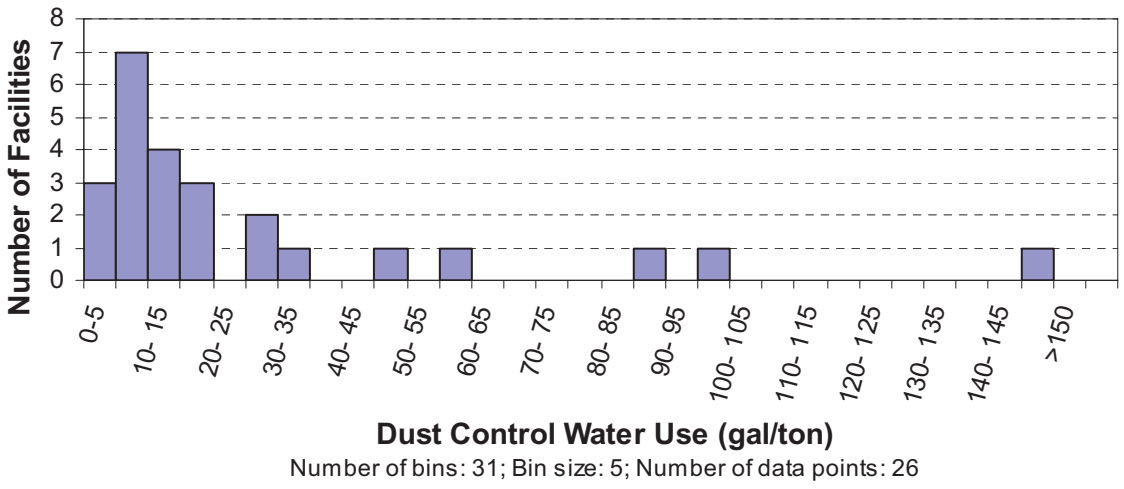
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(b)

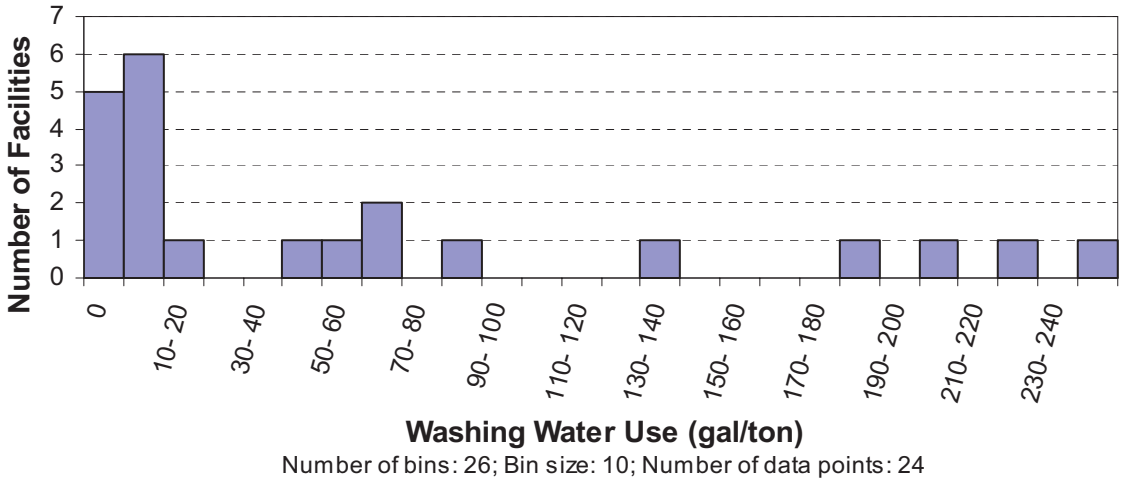
Figure 104. Water use from BEG survey for (a) crushed stone facilities; (b) sand and gravel facilities



(a)



(b)



(c)

Source: BEG survey

Figure 105. Histograms of aggregate net water use for washing and dust control: (a) per facility, (b) and (c) per unit production

4.5 Other Nonfuel Minerals

This section examines water in categories with smaller water use overall, although a few facilities may still use a significant amount of water. The dimension-stone category included many facilities, but other nonfuel facilities are too few to derive water use statistically, and they have to be analyzed individually.

Water use from the cement industry is not included in this section, not because mining of raw material is not mining, but because it is usually associated with a manufacturing SIC code (#3241). There are currently 12 cement plants, which are largely associated with the extensive Cretaceous limestones in Central Texas (Kyle and Clift, 2008). In surveys, it could be difficult to discriminate between water use in the cement plant proper and in the quarries, particularly because water use for most installations is likely to be related to dust suppression only, a small fraction of total usage overall. However, we can still infer an order of magnitude amount of water consumed in mining proper by applying values derived from crushed-rock aggregate installations. In 2009, Texas produced 11 million metric tons of cement (USGS commodity website); about half of it comes from limestone and the other half from clay material. Assuming 10 gal/t for dust control (Figure 105a) for limestone and half that value for clay rocks, yields an estimated total consumption of 250 AF (assuming no stormwater is used). This estimate is corroborated by a BEG survey returned by a large cement manufacturer in the state in which its water-use coefficient for dust suppression is even smaller.

Only one zeolite-producing facility is turning out perhaps 5,000 to 10,000 t of product per year, and total production for the nation is ~60,000 t from 10 mines. Texas is ranked third in terms of production (USGS commodity website, http://minerals.usgs.gov/minerals/). Using the earlier approach, we found the contribution of this mine to water use is negligible. Although minerals such as barite and alumina are also listed in the MSHA database, they correspond to processing facilities not mines.

We applied a similar approach for lime and gypsum, which, as raw materials, are typically transported dry to the processing plant. There is probably little washing of the material for cement, lime, or gypsum plants. Any water use past the quarrying stage would be considered part of the manufacturing process (for example, to soften the material), especially if the water is used within the processing-plant boundaries.

4.5.1 Dimension Stone

Dimension-stone facilities quarry their raw material mostly from Precambrian granites in Central Texas, Permian limestones in North-Central Texas, Cretaceous limestones in Central Texas, and Triassic Limestones in West Texas (Garner, 1992). The MSHA database lists 100+ facilities in this category, and the TWDB WUS survey lists only one facility with no recent water-use data. However, given the small production (44,000 tons in 2007, USGS *Texas Minerals Yearbook*) and assuming water use is related mostly to dust control and cutting, we tentatively based their water use on the highest water use coefficient for the crushed-stone aggregate (151 gal/ton, Table 31). This calculation results in a total water use of 18.5 AF/yr, with the additional assumption that the 10 largest dimension-stone facilities consume most of the water, each using on average 1.8 AF/yr. Even increasing the water-use coefficient by one order of magnitude yields values low enough to be neglected, given the uncertainty associated with larger uses such as aggregates, particularly because many of the counties with dimension-stone facilities also host crushed-stone or lime facilities (Figure 106).

4.5.2 Industrial Sand

Industrial sand, typically used in glass making, foundry molding, and blast sands, has seen an uptick in production and use, probably owing to the large increase in hydraulic-fracturing activities in which it is used as a proppant. Production is concentrated in only a few areas/counties (Figure 107). Texas industrial sand production has increased in sync with U.S. production but seems to be growing faster in the past few years (Figure 108). Some of the operations are owned by gas companies. Current production is likely ~4 million tons (3.28 and 3.58 million tons in 2007 and 2008, respectively, as given on the USGS website (http://minerals.usgs.gov/minerals/).

Industrial sand facilities are similar to aggregate facilities and would require a similar amount of water for dust suppression on roads and conveyor systems but require more water per unit product for washing. Historical water-use coefficients for industrial sands (Table 33) show a total water use ~20 times higher than for aggregates but a higher recycling rate as well (80% in the 1980s). Water consumption averaged across the U.S. was also 10+ times higher than that of crushed stone. The few data points collected for this study agree with this figure.

The Hickory UWCD near the Llano Uplift reported 4,212 AF and 559 AF permitted in McCulloch and Mason Counties, respectively, in a total of five operations most likely related to industrial-sand (proppant) production. The UWCD also stated that actual use and permitted amounts were very close and that plant consumption (manufacturing) was not included. Other sources of information suggest that these two counties produce >1 million tons of industrial sand, particularly the Carmeuse Industrial Sand facility, and perhaps up to one-third of the state output. Assuming the latter sand production value results in a high water-use coefficient of 1,200 gal/t. A facility in Limestone County reports on the TWDB WUS database (http://www.twdb.state.tx.us/wrpi/wus/wus.asp) a consistent ~650 AF/yr throughout the year. A facility responding to the TACA/BEG survey and located in a county north of Houston reported 0.2 million tons of production, water consumption of 315 AF/yr, and a significant fraction (~93%) of the water being recycled. A quick calculation yields a water-consumption coefficient of 514 gal/t for the latter facility, which reports no water use for dust suppression.

How much stormwater is used is unclear. Note that some of the industrial sand facilities are collocated with regular aggregate facilities and that their water consumption may already be included in this category. Overall, when no other information is available, we assumed a water-use coefficient of 600 gal/t, to which we added 20 gal/t for dust control, resulting in **9.7 thousand AF** (Table 36).

4.5.3 Chemical Lime

Lime (and cement) plants tend to be sited next to the raw material (Edwards Limestone, Austin Chalk, and other pure limestones) being quarried. The year 2009 saw a short drop in lime production (1.04 million metric tons; 1.5 million metric tons in 2008), deviating considerably from the trend of the past 2 decades (according to which, production should have been over 1.7 million tons) (Figure 109). According to USGS, as well as the MSHA website (http://www.msha.gov/drs/drshome.htm), there are five lime facilities in Texas, in Bosque, Burnet, Comal, Johnson, and Travis Counties. MSHA provided the annual number of employee-hours, and we assumed that production is proportional to the number of hours worked. Most of the water use in lime facilities is associated with manufacturing. There is typically no washing; operators tend to avoid adding water because of the cost of heating it. Water use is only for dust

suppression and is likely hard to separate from overall plant use. We assumed that water consumption is due only to dust suppression at 10 gal/t (Figure 105a). The result is a small total water consumption of **46 AF** (assuming no stormwater is used) (Table 37), which can be neglected.

4.5.4 Clay Minerals

Clay minerals mined in Texas fall into two categories—common clay (brick making, cement component) and specialty clays (ball clay, bentonite, fire clay, Fuller's earth, kaolin). These five types' usage and mineralogical make-up are: ball clay (kaolinitic sedimentary clays that commonly consist of 20–80% kaolinite, 10–25% mica, 6–65% quartz), which is used for ceramics; bentonite, which is used for drilling mud, among many other uses; fire clay (all clay minerals but bentonite), which is used to make refractory products; Fuller's earth (montmorillonite or palygorskite or a mixture of the two), which is used as a adsorbent; and kaolin (kaolinite), which is used for porcelain and high-quality paper (Norvell, 2009, p.6).

Clay mining is generally performed by scrappers, which remove materials and transport it to stockpiles for use in manufacturing processes, such as brick making. In some mines, excavators are used to remove and load clay onto railcars, barges, or other transport to off-site manufacturing plants. Clay mines may be online for only a few months each year to provide raw materials sufficient to support manufacturing throughout the year. No water is used in the actual mining process, although water is added during most of the manufacturing processes. In fact, clay mines are bermed to minimize rainwater inflow and must be dewatered, if necessary, to allow access and prevent excess water from affecting clay quality. Water is discharged into retention ponds or nearby surface water, and some is used for dust suppression on plant roadways. Water can be used for conveyance as slurry but cannot be included as mining use; it is instead considered as manufacturing use.

Texas clay deposits are generally contained in Tertiary formations of the Gulf Coast. Brick-making operations often tap the common clay of the Calvert Bluff Formation in Central Texas (Hunt, 2004). Altered volcanic ash layers in South Texas provide bentonite, and kaolinite is produced from the Simsboro Formation in North Texas. The main clay producers are in Gonzales (bentonite), Navarro (common clay), Limestone (kaolin), and Fayette (bentonite) Counties. Clay is also mined in an additional 20 counties.

Texas mining production in 2008 was 2.14 million tons of various clay minerals, having remained relatively constant at that level during the past decade despite a bump of ~2.7 million tons in 2006 and 2005. Less water is probably needed for dust suppression in clay operations, and stormwater probably ponds more easily than in conventional aggregate operations. However, unlike for cement, lime, and gypsum operations, the clay washing step could be included as mining use, which we ultimately decided not to do. Assuming a water-use coefficient of 30 gal/t (Figure 105c) would have yielded only **~200 AF**, a low value that falls below the uncertainty level of major users and is distributed across various operations in several counties.

4.5.5 Gypsum, Salt, and Sodium Sulfate

Gypsum is produced mostly from Permian evaporitic strata of North-Central Texas in Nolan/Fisher/Stonewall Counties and Hardeman County, as well as in Gillespie, Kimble, Wheeler, and (perhaps) Harris Counties. Texas production in 2008 was ~1.04 million metric tons and has seen large variations in production in the past decades, although seemingly relatively stable at 1.8 million tons/yr on average (Figure 110). The number of mining facilities has also

changed in sync with total production (four, five, or six facilities). The result is a small total water consumption of **32 AF** (assuming no stormwater is used) (Table 38).

There are only two salt mining operations in Texas: the Grand Saline Dome in East Texas in Van Zandt County and the Hockley Dome in the Houston area in Harris County, both of which use the classic room-and-pillar mining technique. The USGS commodity website (http://minerals.usgs.gov/minerals/) reports that the Hockley and Grand saline mines had a production capacity of 400,000 and 150,000 short tons of rock salt in 2008, respectively. Texas total salt production has ranged from 9 to 10 million metric tons/ yr in the past decade (9,080 metric tons in 2008), ~20% to 25% of national production. In 2006, Morton-Thiokol's salt mine in Grand Saline in Van Zandt County reported the use of self-supplied groundwater of 384.4 AF, diversion of 43.3 AF of surface water, and groundwater purchase of 43.5 AF, totaling 471 AF/yr (Table 39) (K. Kluge, TWDB WUS, personal communication, 2006). The Harris-Galveston Subsidence District reported that the Hockley mine in Harris County uses ~0.1 to 7.0 Mgal/yr from groundwater wells. The district is also purchasing surface water from the Gulf Coast Water Authority for ~150 to 200 Mgal/yr, which comes to a total of ~535 AF/yr and **1.0 thousand AF** overall (Table 39). However, solution mining is the most common method of obtaining salt. In theory, 800 gal of water is required to recover 1 metric ton of salt with little recycling. In Texas, salt is used mostly as a chemical feedstock for producing chlorine (a key ingredient in the production of plastics) and soda ash (a key ingredient in the manufacture of glass) and the salt-saturated brine is directed toward the manufacturing process. For example, Dow Chemical in Brazoria County uses water from the Brazos River and is injected onsite to recover salt for use in the chemical plant. The ~9 million tons of salt annually produced in the state minus underground mining production and minus 0.8 Mt evaporated at Baytown brings the total salt production through brine at 7,700,000 × 800 = ~19,000 AF. This use of feedstock in the chemical industry is considered manufacturing and is not included in the mining category tallied in this report.

Sodium sulfate mining is extracted from brines underlying alkaline lakes in West Texas (Kyle, 2008; Kyle and Clift, 2008), one of two such facilities in the U.S. The TWDB WUS survey shows annual groundwater withdrawals remaining consistently at ~400 AF in Gaines County in the past decade. Norvell (2009) noted that early in this decade the facility pumped 1,440 AF/yr, 1,092 AF of which was saline water, increasing our confidence that the earlier mentioned **400 AF** is fresh groundwater, not produced brine (which should not be counted toward water use). We assume that sulfate sodium production and concomitant water use remained stable in the study period. Growth of this commodity will be covered by sources other than mining natural accumulations.

4.5.6 Talc

National production of talc decreased from 0.85 million tons in 2005 to 0.51 million tons in 2009 (USGS website, http://minerals.usgs.gov/minerals/). It is produced from seven mines. Talc in the Allamoore district of Hudspeth and Culberson Counties in West Texas is produced from several quarries at ~100,000 t/yr. The most recent TWDB WUS (2003) reports a low water use of 1 AF. However, RWPG Region L (Far West Texas) initially prepared a report (2010) citing a value of 1,500+ for Culberson County, increasing to 1,600+ in 2060 (see their section 2.4.7). The quarries are apparently in Hudspeth County, whereas the wells appear to be in Culberson County. The water consumption value was derived using a water-use coefficient approach (from USGS) and not using direct metering. Whether this figure includes processes that would belong to the manufacturing category is unclear. We were unable to collect better information, and we expect

no change in water use in the decades leading to 2060, assuming water consumption to be classified as mining ~0.

4.5.7 Uranium

Although uranium could be considered a fuel for nuclear power plants, its main use, for convenience, is treated in this section. Only in situ leaching (ISL) or in situ recovery (ISR) technology is currently used to mine uranium (Campbell et al., 2007). The two main kinds of water-use consumption are (1) active mine and (2) reclamation/restoration, the latter requiring more water by far, although overall, the uranium extraction industry uses little water. A typical operation consists of injecting water with oxygen into the ore zone and producing the uranium-laden water, removing the uranium in ion-exchange resin, and reinjecting the water at a high recycling rate (>97%). The restoration phase follows, in which other soluble elements are brought back close to initial concentrations. A reverse osmosis technology is generally used. The recycling rate is lower, perhaps 33%, at least initially. As trace-element concentrations decrease, the RO system can be pushed further, resulting in a decreased waste stream. Other technologies, such as bioremediation, could consume less water. A given ISR facility often produces uranium and restores the subsurface at different nearby locations simultaneously. We retained an average value of 250 gal/ lb of uranium as an overall representation of water consumption.

Uranium production is concentrated in South Texas (Blackstone, 2005; Carothers, 2008, 2009; Nicot et al., 2010). EIA reported (http://www.eia.gov/nuclear/) that in 2009 only two ISL operations were active in Texas: Alta Mesa (Brooks County) and Kingsville Dome (Kleberg County). In 2008 two more were operational: Rosita and Vasquez, both in Duval County. In the past few years uranium production in the U.S. has been close to 4 million lb U_3O_8 (Figure 111) and was 4.145 million lb U_3O_8 in 2009. These facilities have a nominal production of 1 million lb U_3O_8 each (except Vasquez, at 0.8 million lb U_3O_8). EIA reported only aggregated data to protect individual companies. With the additional help of survey returns, we estimated Texas production at ~28% of total production (that is, ~ 1.1 million lb U_3O_8). We reached this value by contrasting (1) production capacity in Texas (5.3 million lb U_3O_8 in 2009) with that of the U.S as a whole (20.45 million lb U_3O_8), that is 28%, with (2) employment numbers at 31% in Texas and Colorado the total number of employee-years. Clift and Kyle (2008) reported a total production of ~1.34 million lb U_3O_8 in 2007, more than two-thirds of it from Brooks County (Alta Mesa Project). This level of production results, in turn, in a water consumption of 275 million gal, or **840 AF,** for all producing mines in Texas. We assumed that restoration water consumption is combined with production. Because the number of operating mines is limited, actual water consumption can be much lower if no restoration is being done. For the purpose of this study, we attributed one-third of the estimated total to each county (Table 40). Reclamation by RRC of legacy open pits produced in the second half of the 20th century is not included in this count.

4.5.8 Other Metallic Substances

Texas has many other occurrences of metallic and industrial minerals, notably in west Texas and in the Llano Uplift of central Texas (e.g. Price et al., 1983; Price et al., 1985; Kyle, 1990; Kyle, 2000). Some of these deposits have had minor production, but most known deposits are currently inactive. The scale of known resources provides little encouragement that most could represent viable mining operations in the foreseeable future. On the basis of decades-long evaluation and development activities, three deposits seem to have potential for near-term mining: (1) Shafter silver deposit, Presidio County; (2) Round Top beryllium-uranium-rare earth element deposit,

Hudspeth County; and (3) Cave Peak molybdenum deposit, Culberson County. They will be examined in the ‘Future Water Use” section.

Table 36. Estimated county-level industrial sand-water consumption

County	Estimated Number of Facilities	Estimated Water Use (1000s AF)
Atascosa	3	0.43
Colorado	3	0.43
Dallas	1	0.04
El Paso	1	0.04
Guadalupe	1	0.07
Harris	1	0.14
Hood	3	0.43
Hunt	1	0.07
Johnson	1	0.04
Liberty	2	0.14
Limestone	2	1.30
Mason	1	0.56
McCulloch	4	4.21
Montgomery	2	0.76
Newton	1	0.14
Orange	1	0.07
Robertson	1	0.04
San Saba	2	0.28
Smith	1	0.07
Somervell	1	0.14
Tarrant	3	0.21
Wise	1	0.07
Total	**23**	**9.68**

Table 37. Estimated county-level lime mining-water consumption (AF)

	Water Consumption (AF)
Bosque	8.5
Burnet	2.8
Comal	6.6
Johnson	13.1
Travis	15.1
Total	**46**

Table 38. Estimated county-level gypsum mining-water consumption (AF)

	Water Consumption (AF)
Fisher	3.3
Gillespie	3.3
Hardeman	6.6
Kimble	1.5
Nolan	14.8
Wheeler	1.2
Total	**32**

Table 39. Estimated county-level salt mining-water consumption (AF)

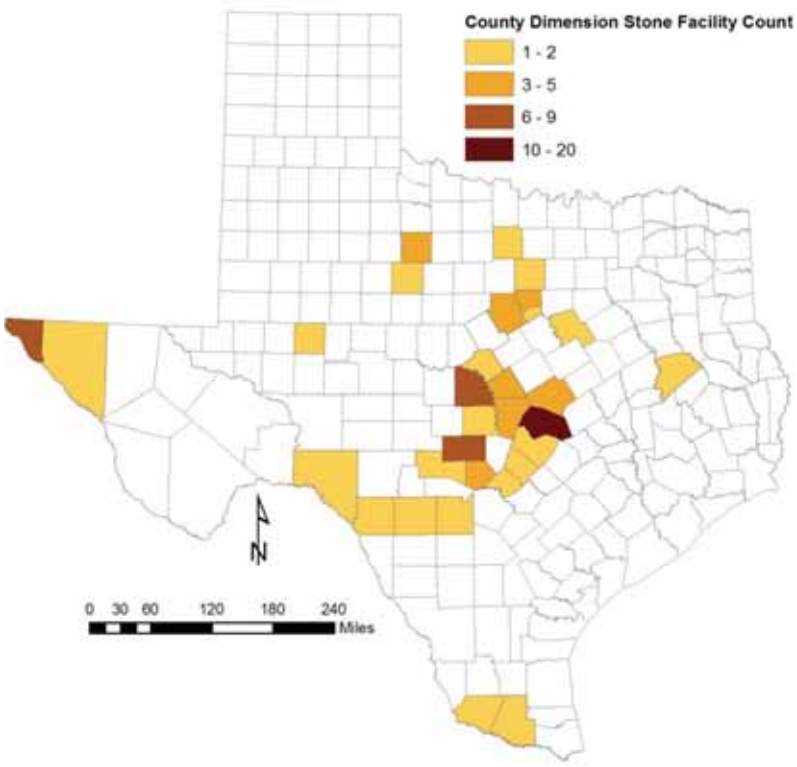
County	Water Consumption (1000s AF)
Harris	0.535
Van Zandt	0.471
Total	**1.01**

Table 40. Estimated county-level uranium mining-water consumption (2009)

County	Water Consumption (1000s AF)
Brooks	0.28
Duval	0.28
Kleberg	0.28
Total	**0.84**

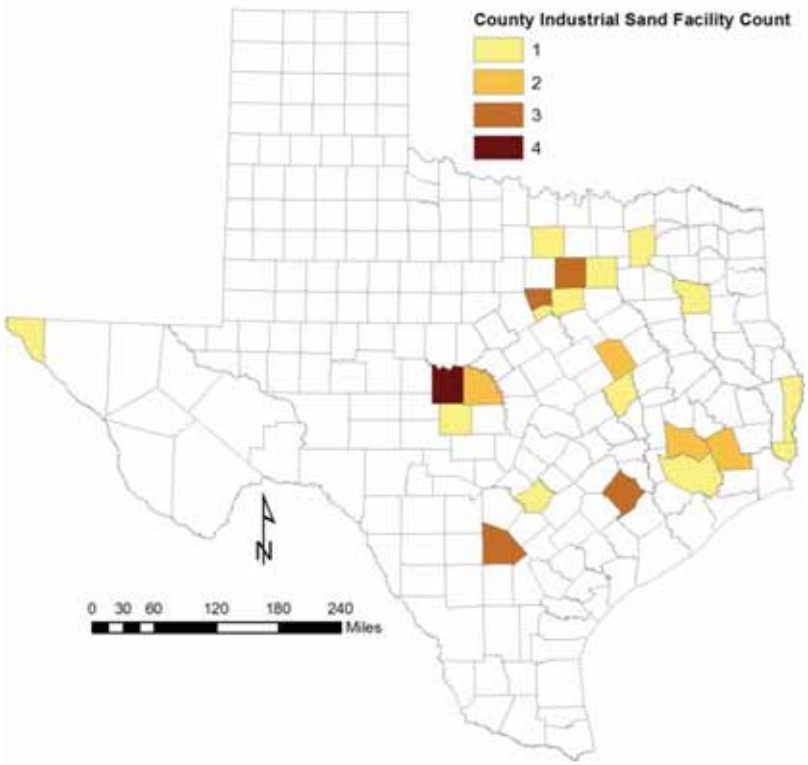
Table 41. Summary of water use not in the oil and gas, coal, or aggregate categories

Mined Substance	Estimated Water Consumption (1000s AF)
Dimension Stone	0.018
Industrial Sand	9.7
Chemical Lime	0.046
Clay Minerals	0.2
Gypsum	0.032
Salt	1.01
Sodium Sulfate	0.4
Talc	~0
Uranium	0.84
Zeolite	~0
Cement	N/A
Total	**12.25**



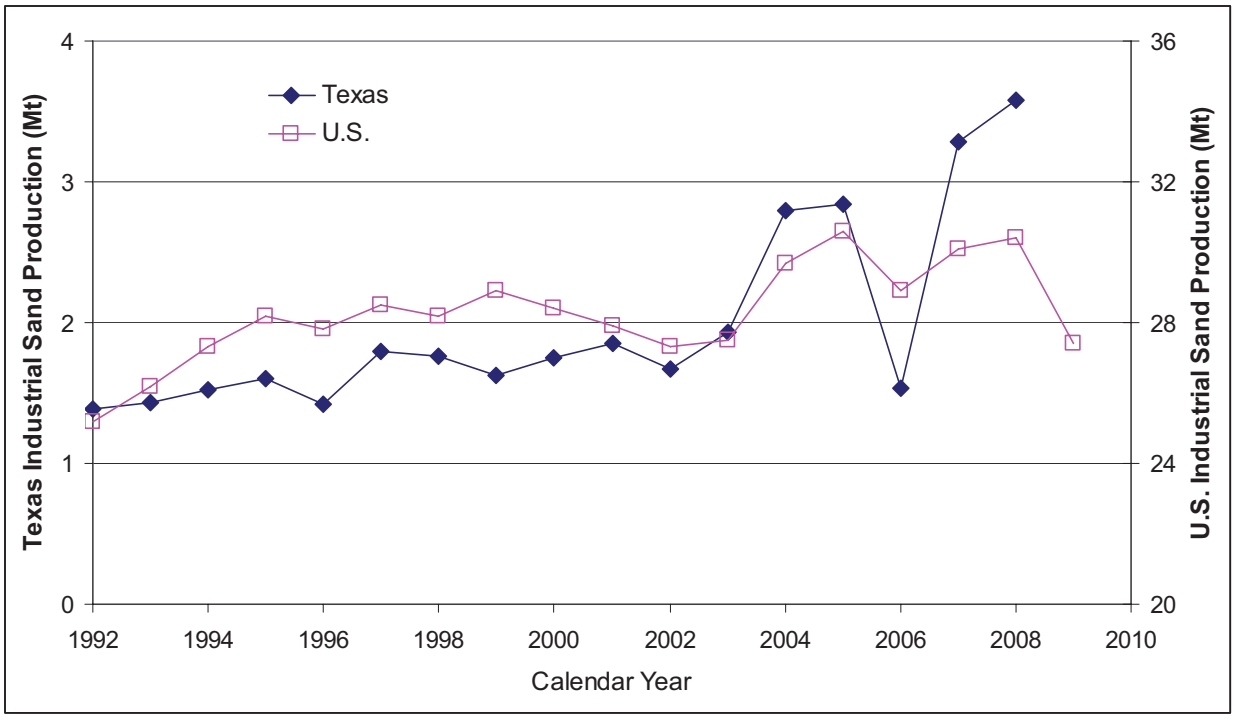
Source: MSHA database

Figure 106. County-level count of dimension-stone facilities



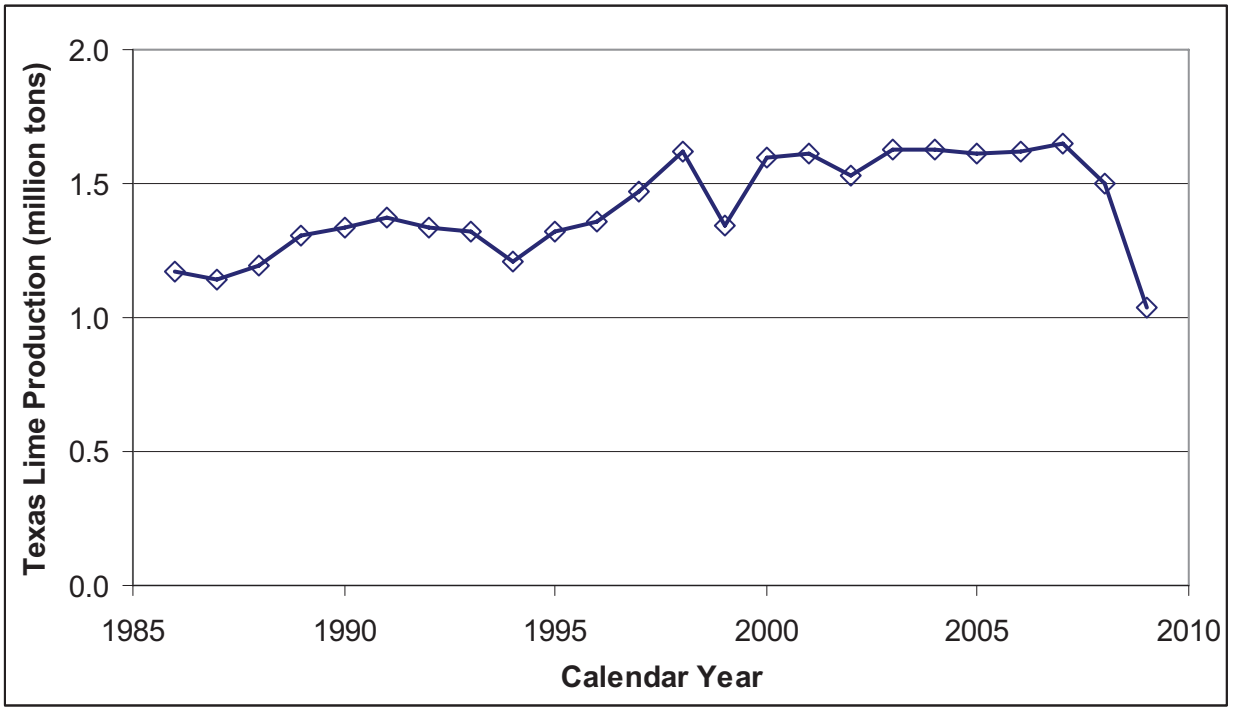
Source: MSHA database

Figure 107. County-level count of industrial-sand facilities



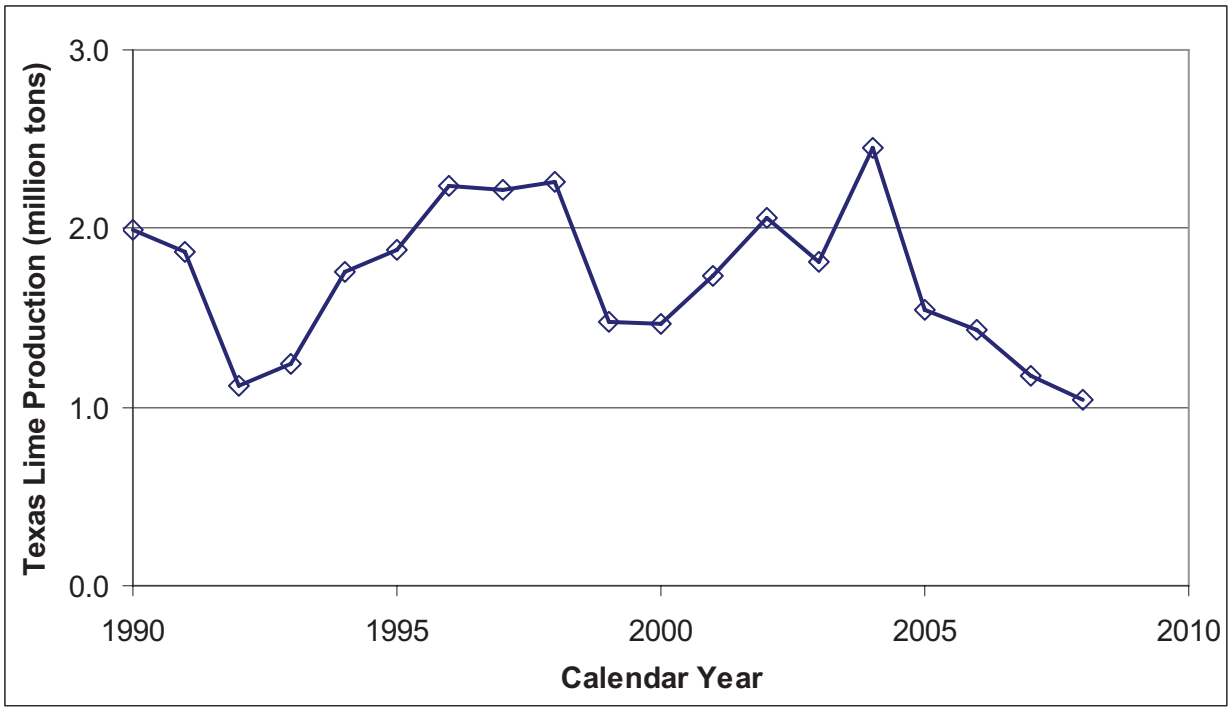
Source: USGS commodity website

Figure 108. Texas and U.S. industrial-sand production (1992–2008)



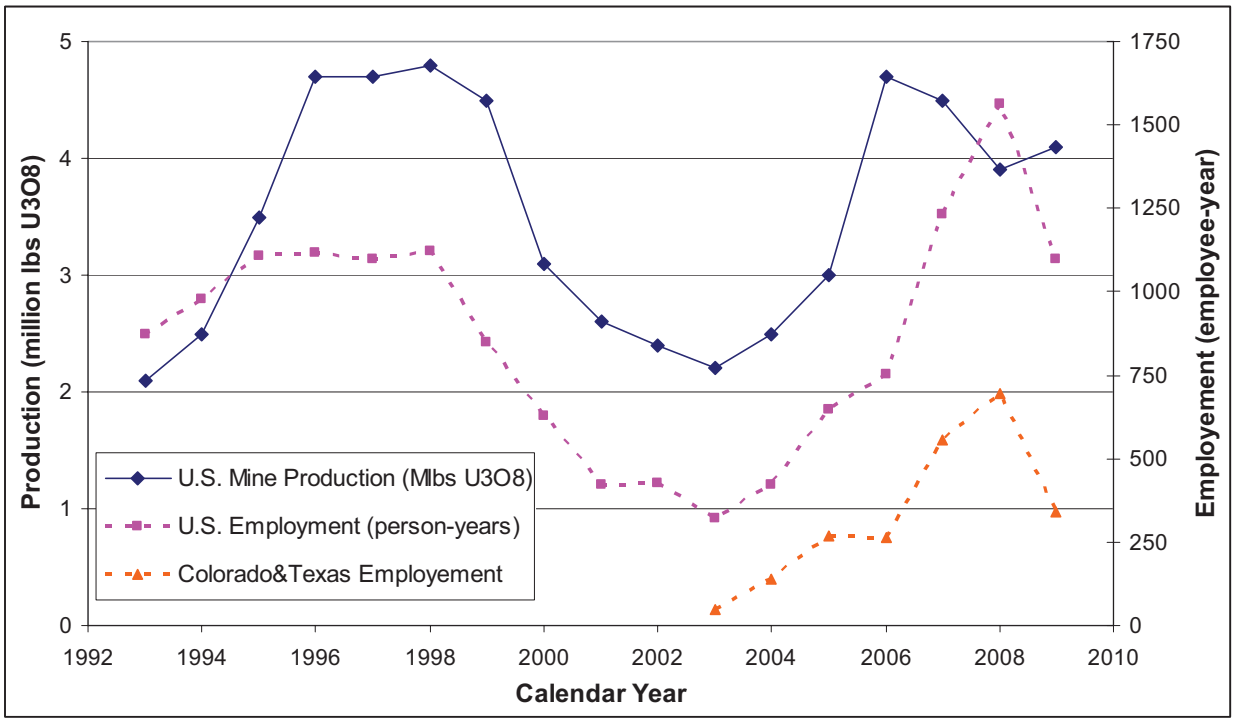
Source: USGS commodity website

Figure 109. Texas lime production (1986–2009)



Source: USGS commodity website

Figure 110. Texas gypsum production (1990–2008)



Source: EIA website

Figure 111. U.S. uranium production and employment (1993–2009)

4.6 Historical Mining with High Water Use

Although no longer active, mines once having high water use should be noted.

Sulfur

Once Texas was a major producer of Frasch sulfur from microbially altered evaporitic strata in west Texas (Hentz et al., 1989) and in salt dome cap rocks of the Gulf Coastal Plain (Kyle, 2002). More than 350 million tonnes of sulfur were produced using the Frasch process from these native sulfur deposits in Texas, Louisiana, and Mexico during the 20th century (Kyle, 2002). As recently as 1999, Frasch sulfur was produced from the Culberson deposit in Culberson County, one of the largest deposits of this type. Four smaller deposits in Pecos County had lesser amounts of Frasch sulfur production through the 1980s (Crawford, 1990).

The shallow salt domes of the Gulf Coastal Plain were the sites of significant historical sulfur production (Myers, 1968; Flawn, 1970; Greene, 1983, p. 10; Kyle, 2002). The Boling salt dome cap rock in Wharton County was the largest known Frasch sulfur producer in the United States, with more than 87 Mt of production from 1916 until 1993. Other Texas counties with multiple historical Frasch sulfur producers include Brazoria (4), Fort Bend (4), and Jefferson (2). Other counties with single producers include Chambers, Duval, Liberty, and Matagorda. Most of the economic sulfur concentrations seem likely to have been exhausted during the Frasch mining period.

The Frasch process requires extensive amounts of superheated water to inject into the native sulfur-bearing zone to melting the sulfur, allowing the pumping of liquefied sulfur to the surface (Ellison, 1971). The economics of the Frasch process dictate extensive recovery of water and its contained heat. Water usage in association with Frasch sulfur production at the Culberson deposit was nominally 2,000 gal per tonne of sulfur produced (J. Crawford, written communication, 2010), but with only 5% of the total water being "make-up" water for the sulfur extraction, i.e. 95% of the process water is recycled. Thus, using those figures, the water demand for the Culberson operation at a rate of ~2.5 million tonnes per year totaled about 900 AF per year (1990 case; Crawford, 1990). This make-up water was supplied from wells in Reeves County, 37 miles southeast of the sulfur production site (Crawford, 1990; Crawford et al., 1998).

Bituminous Coal

Texas bituminous coal occurs in six coalfields in North-Central Texas, Maverick County, and Webb County. More specifically, coal resources occur in the Eagle Pass, Santo Tomas, Eagle Spring, San Carlos, Big Bend, and west of Fort Worth in North-Central Texas. The largest annual production of bituminous coal occurred in 1917, with >1.25 million tons of bituminous coal produced in the state, followed by a steep decline in the early 1920s that was due to competition from oil and gas. Production of bituminous coal ended in 1943 after 15 yr of low production, <100,000 t/yr (Evans, 1974). Coal from these areas has been extensively mined, and we assume no further production through the next decades.

4.7 Conclusions and Synthesis for Historical Water Use

In 2008, the mining industry, defined as described in Section 4, consumed ~140 thousand AF of fresh water, distributed in a relatively balanced way between its main users (Figure 112). The oil and gas industry used ~57 thousand AF (41%), whereas the coal and aggregate industry used ~27 (19%) and ~43 (31%) thousand AF, respectively. The "other" category (~12 thousand AF,

9%) is dominated by industrial sands. A more detailed breakdown (Figure 113) shows that water use included 35.8 thousand AF for fracing wells (mostly in the Barnett Shale/Fort Worth area) and ~21.0 thousand AF for other purposes in the oil and gas industry. Aggregate industry water use is distributed between crushed stone (24.7 thousand AF) and sand and gravel (18.3 thousand AF). Remaining water use amounts to 12.2 thousand AF and is dominated by industrial sand production (~80% of total).

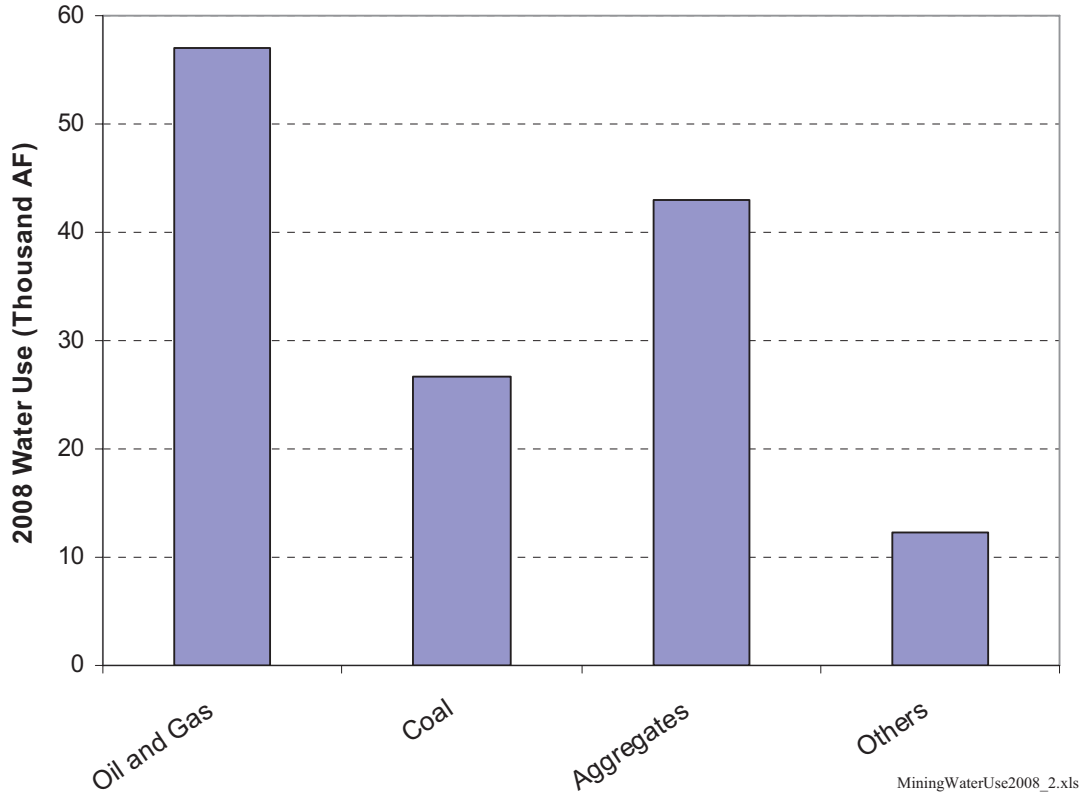


Figure 112. Summary of water use by mining industry segment (2008)

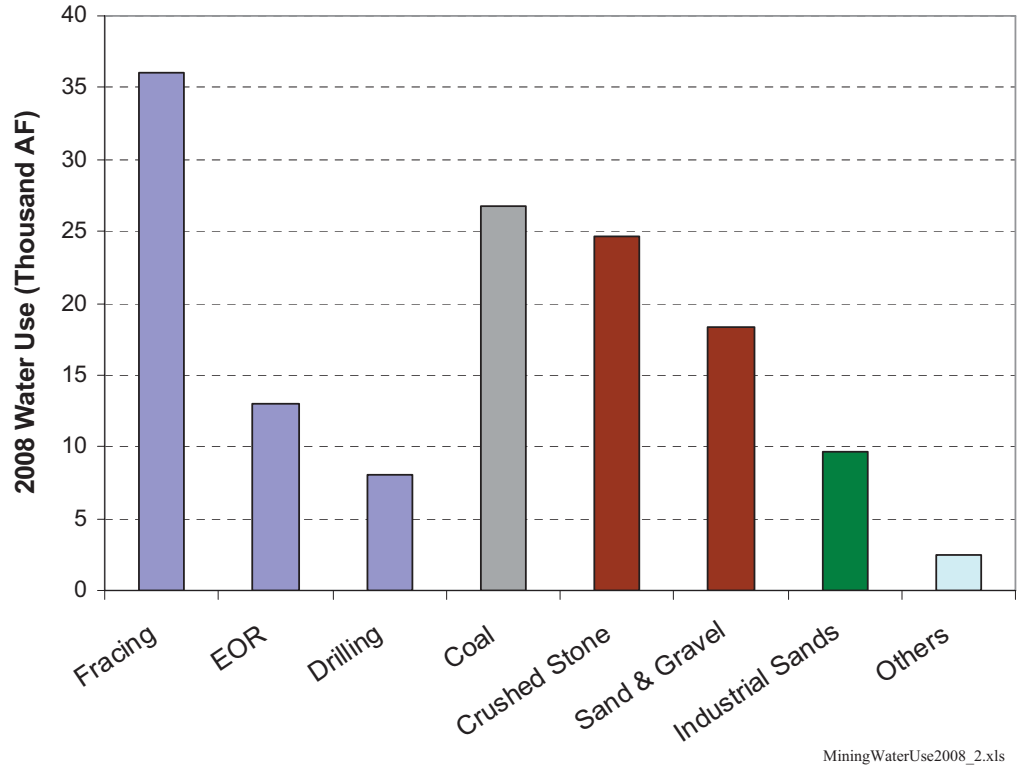


Figure 113. Summary of water use by category (2008)

5 Future Water Use

Most uncertainty about future water use in the mining category comes from unknowns in the rapidly evolving exploration of shales and tight formations, whose gas production is ultimately tied to national economic activity. Aggregates and coal-mining water use are better constrained and directly driven by local conditions, such as population growth, but are also connected to national economic activity. The latter is the most important driver for oil and gas long-term trends of interest to this study. An element strongly impacting future water use is the national energy policy, particularly the impact of any cap-and-trade legislation. The passage of some cap-and-trade or carbon-tax legislation during the next decade is likely to boost gas-fueled power plants, but it may also boost oil production through a greater availability of CO_2 needed for tertiary recovery of oil currently nonrecoverable (assuming the type of WAG CO_2 flood common in the Permian Basin).

In the short term, oil and gas operators are likely to focus on plays such as the Wolfberry or the combo play of the Barnett Shale or the Eagle Ford, all producing oil with significantly better economics than gas. Gas is typically a regional commodity and does not travel as well as oil, which is a world commodity. This fact is currently reflected in current oil and gas prices. In terms of BTUs contained, oil and gas prices have tracked each other fairly well until about a decade ago. It follows that variation/change in price will vary more wildly for gas. Unless lease agreements were made early in the history of the plays, Barnett Shale or Haynesville Shale operators are probably on the wrong side of the breaking even at current low gas prices. The economic slowdown has also impacted aggregate and other material demand, as well as power demand. However, overall, we refrained from trying to model this short-term episode.

5.1 Gas Shales and Tight Formations

Future water use depends on the amount of oil and gas still in the ground that is ultimately recoverable. Resources are enormous. Holditch and Ayers (2009) suggested that technically recoverable reserves in any basin are 5 to 10 times the amount of conventional gas produced and reserves are from >10 times in the Fort Worth Basin to less than the average in the Gulf Coast, and it is very likely that the industry will operate beyond the Barnett, Haynesville, and Eagle Ford shales, which it is currently focusing on. From a practical standpoint, however, this study had to rely on spatially defined resources from published information. The shale-gas industry agrees that there will be no major discovery of gas shales in Texas, whose geology is well known (e.g., Chesapeake CEO, 2010).

National organizations that develop, compile, and distribute national assessments of oil and gas reserves and resources (USGS, EIA, AAPG, PGC) have a hard time keeping up with rapid changes in the field. Figures provided by these organizations and others are not necessarily consistent as to the cutoff date for production, and other criteria may differ (resources and reserves vary through time as some are produced and additional ones are discovered), and the spatial footprint considered might be different or include areas outside of Texas. A compounding factor is that available data may not refer to a particular formation but simply a geographic area. Organizing such a large pool of information was a challenging endeavor, and we integrated the different and sometimes conflicting figures as best we could, given the time and budget constraints. As a comparison benchmark, state-level current gas production is ~7–8 Tcf/yr and increasing, whereas oil production is 0.3–0.4 Bbbl/yr. The latest figures from EIA are from 2008

(Table 43) and are categorized by RRC district (see map in Figure 9 for locations), as well as information on proved reserves. Speculative/undiscovered resources were provided by USGS (Table 43) and are not entirely consistent with data collected from other sources (Table 44). Overall, we assumed a total of 52 Tcf to be produced from the Barnett Shale. Eagle Ford and Haynesville-TX + Bossier-TX production potential is not included specifically but can be estimated at 161 Tcf and 28 + 21 Tcf, respectively. Permian Basin Barnett and Woodford USGS projections (Table 44; Schenk et al., 2008) seem optimistic and are assumed to be at ~20 Tcf. On the other hand, Wolfberry potential seems to be underestimated. Schenk et al. (2008) included only the Spraberry at a proposed ~510 million barrels of unconventional oil.

More generally, the Schenk et al. (2008) study is an example of a resource assessment performed periodically by the USGS. Unfortunately, information on other important basins in Texas has not been updated yet and the recent sharp increase in resources has not been taken into account. The Fort Worth Basin assessment (USGS, 2004) dates back to 2003, and work on the Cotton Valley and Travis Peak Formations was performed in 2002. USGS (Schenk et al., 2008) provided figures for undiscovered resources in the Permian Basin and divided them into conventional and "continuous" resources. Continuous undiscovered resources were estimated at 35 Tcf of gas and 1.3 Bbbl of oil and NGL. Overall the document may overestimate the potential of the Woodford and Barnett Shales and underestimate that of the Spraberry/Wolfberry. The same document assessed that 0.747 Bbbl oil, 5.2 Tcf gas, and 0.236 Bbbl NGL remain to be discovered, which is in addition to the ~5 Bbbl and ~0.3 Tcf of proven conventional reserves (Dutton et al., 2005b, p. 554). In the end, we estimated that the Wolfberry will produce ~1 Bbbl in the coming decades.

In general, we favor more optimistic predictions (more resources, more production, more water use) because predictions by EIA seem to have systematically underestimated actual production for the past decade because of unconventional gas. By combining proven and undiscovered recoverable resources (Table 43), we assume that the next 5 decades will see 10 Tcf produced from the Anadarko Basin, 16 Tcf from the East Texas Basin, 11 Tcf from the Gulf Coast Basin, and 15 Tcf from the Permian Basin (all tight gas and not necessarily all production).

5.1.1 Projected Future Water Use of Individual Plays

We next address gas shales individually (Barnett, Haynesville, Bossier, Eagle Ford, Pearsall, Woodford-PB and Barnett-PB) and basins with tight producing formations. Table 45 summarizes operational characteristics as collected from the literature to provide guidance for the parameters used in the production-based approach (see Methodology Sections 3.4.1.1 and 3.4.1.2). Parameters used for the production-based and resource-based projections are summarized in Table 46 (gas shales) and Table 47 (tight formations). Water use is contingent on the price of gas, and drilling activity is more sensitive to price than production. All gas plays, even with marginal permeability, will be fraced if gas prices reached $10/ Mcf, even more if the gas contains condensate, and development will be accelerated relative to that projected in this section. Conversely, if the price of gas stays below $5/Mcf for an extended period of time, projections may turn out to be too high in terms of water use.

Given the current low price of gas relative to oil in terms of BTU content, more companies have become interested in wet gas, that is, gas that contains significant amounts of ethane, propane, and butane (that can form liquid at surface conditions), whose price more closely follows that of oils. Alternatively, operators are moving altogether into the oil window of the shale. This business transition is occurring in the Barnett, Eagle Ford and Granite Wash. The net effect on

water use will be to stabilize the amount used at the state level because companies will likely oscillate between dry and wet gas as a function of natural gas price.

All basins but the Gulf Coast Basin show an increase in gas production in the recent study by the PGC (PGC, 2009), in which the U.S. is divided into work areas that follow the general geology: P-320 (East Texas), P-330 (Gulf Coast), P-430 (Fort Worth Basin), and P-440 (Permian Basin, including New Mexico and West Texas) (Figure 115). The East Texas Basin has shown an increase in both production and well count in the past few years after a long period of stability. Between January 2004 and December 2008, production increased from ~3,000 to ~5,000 MMcfd, with ~10,000 incremental wells. The Fort Worth-Strawn Basins, after a slow decline in terms of production (~600 MMcfd) and well count since 1990, have shown a turnaround that started ca. 2000 and that corresponds to initial development of the Barnett Shale. Starting then, production increased to 2500 MMcfd in 2007 and increased faster to reach ~5000 MMcfd at the end of 2008. Gulf Coast production stayed more or less stable at 6,000 to 7,000 MMcfd but has been on a slow decreasing trend since 2000. The well count is stable as well. Production in the Permian Basin has remained stable at 4,000 MMcfd for the past 20 years (to the end of 2008), with an increase in well count showing the maturity of the plays and infill drilling.

Barnett Shale

The Barnett Shale represents a special case because a similar study was completed a few years ago (Nicot and Potter, 2007; Nicot, 2009a). Appendix B suggests that projections are correct so far. For the present study, we went back to initial projections at the county level (Bené et al., 2007, Table 8, Appendix 2; Nicot and Potter, 2007, Table 8), supplemented by the study by Tian and Ayers (2010), who presented an update on the prospectivity of the shale in both the oil and gas windows. We also noted that average water intensity seems to have decreased from the estimated 1.2 Mgal/1,000 ft of lateral in Nicot and Potter (2007) to ~1 Mgal/1,000 ft, despite (or thanks to) an increase in lateral length.

County-level results are presented in Table 48. Water use projections peak in 2017 at ~43 thousand AF and then decrease to almost nothing in 2040. High-water-use counties are outside the core area because it has already passed its peak of drilling activity. Parker, Tarrant, and Wise Counties, for example, have a high water use, although it will drop during the next decade as activity moves to Clay and Montague Counties in the oil window and more peripheral counties outside of the core area.

Haynesville/Bossier Shales

The part of the Haynesville/Bossier shales lying in Texas is estimated at ~35% of each play. We also added a few counties west of the salt basin slated to start producing at a later date. Projections suggest that water use will peak at 22 thousand AF around the 2020 (Table 49 and Table 50). As expected (as well as by construction), counties from the core area (Harrison, Panola, San Augustine, Shelby) are projected to peak at the same time and to contribute the most to total water use.

Eagle Ford Shale

Because of the relative lack of information on Eagle Ford wells, the Eagle Ford Shale decline curve is assumed to be similar to that of the Haynesville but scaled by a smaller EUR. Cusack et al. (2010) attempted a similar analysis in the Eagle Ford play and concluded that 50,000 wells would be needed. This study came up with twice as many wells but spread over a much larger

area. The Eagle Ford Shale was projected to peak in 2031, with a water use of ~32 thousand AF (Table 51). Leading counties in terms of water use are such mostly because of their size because no core area has been delineated yet and water use is distributed over the whole play more or less evenly (but not entirely because of prospectivity variations still).

Permian Basin Barnett and Woodford Shales

Those two potentially gas-bearing shales cover large tracts of land in the Delaware Basin in West Texas and overlap (making them more attractive to operators). They have been tested several times, apparently with little success. Matthews et al. (2007) suggested that the lack of carbonates to the Barnett Permian Basin relative to the Fort Worth Basin subcrops is an unfavorable element. We also think that the level of interest is currently low. Mineral-rights owners would rather produce shallower oil with a more dependable worth. Similar to the Pearsall Shale, we assumed a delayed start of around 2020. Water-use is projected to peak at 9.8 thousand AF in 2031 (Table 52).

Pearsall Shale

The Pearsall play has not been very active in the past couple of years but has showed potential in the past. It was assumed that after a period of time, operators in the Eagle Ford would redirect their attention to this play, which is slated to use water in significant amounts around 2020 and peak in 2031 at ~8.1 thousand AF (Table 53).

Wolfberry Trend

The Wolfberry Trend is assumed continuous and is treated in a way similar to that of gas shales. Projections result in a 2023 peak year, with a water use of 11.7 thousand AF. Counties with the highest water use are Irion, Reagan, and Upton Counties (Table 54).

Tight-Gas Plays

Tight-gas plays are discontinuous and cannot be approached exactly as the gas shales were. In addition, most of them have been producing both conventional and tight gas for many years. Their water use is also smaller for these very reasons: less gas to recover and only a small fraction of a county is of interest. Water use in the East Texas Basin tight-gas plays (Table 55) is projected to peak in 2024 at 5.5 thousand AF, with no county dominating. Water-use projections for the Anadarko Basin (Table 56) peak at 3.1 thousand AF in 2020, with a strong contribution from Hemphill and Wheeler Counties. The south Gulf Coast Basin (Table 57) has a small projected water use of 2.4 thousand AF distributed over many counties at its peak (2027), in agreement with the low level of interest local plays have received in the past few years. The Permian Basin (Table 58), which has a higher potential, shows the highest water use in 2017 at 7.8 thousand AF, distributed over many counties as well.

5.1.2 Correcting Factors

Correcting factors include recycling, refracing/infill drilling, and potential development of new technologies.

5.1.2.1 Recycling

Recycling figures depend on two parameters: (1) how much of the frac water flows back and how soon after the fracing operation itself? and (2) what fraction of it is usable again with or without treatment? The amount of water ultimately flowing back from an average fraced shale-gas well is a strong function of the play. It can vary from three times the volume injected in the

Barnett Shale to a small fraction, as in the Marcellus in Pennsylvania. From a strictly operational standpoint, only the water flowing back early (10 days) in the history of the well is reusable, when all the water infrastructure is still in place (although a multiwall pad may mitigate this). The fraction of injected frac water satisfying this criterion is 16% and 5% in the Barnett and Haynesville Shales, respectively (Table 42). In addition, the quality of the such-defined flowback water is variable. Some initial flowback water can be reused with little treatment (filtration or/and mixing). Blauch (2010) stated that flowback water can be used without much treatment, mostly by straight blending with fresh water (5–10% flowback and 90–95% fresh water) and using new-generation chemical additives. However, Rimassa et al. (2009) suggested that full recycling will be hard to attain because degraded additives accumulate in the recycled water. At the other end of the spectrum, undergoing full recycling using more or less advanced treatments and producing distilled water can be expensive. However, a whole segment of the service industry has grown in the past decade to address the recycling needs of gas operators with the development of many mobile water-treatment units making use of different technologies (Horn, 2009), such as osmosis, reverse osmosis, and thermal processes.

The RRC website (http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php, accessed 10/11/2010) mentioned that a company specializing in recycling of industrial water has treated enough produced water (at 80% recovery) to generate 9.3 million barrels of fresh water thanks to several mobile units. This amount is equivalent to 1.2 thousand AF over the course of a few years (since 2005). The RRC website also announced that a stationary facility in Parker County with a capacity of 30,000 bbl/d received the go-ahead. This capacity amounts to a production of 1.13 thousand AF of recycled water a year, assuming no down time. Devon, using recycling mobile units, has recycled >400 million gallons, with an efficiency of ~80% (that is, >320 Mgal (~1 thousand AF), which was reused and >80 Mgal had to be disposed of (Devon website). This information has been reprised by RRC, as described earlier. It seems that only Devon has heavily invested in making use of flowback and treated produced water. According to the IHS database, Devon has drilled ~20% of the Barnett wells since 2005. The process did not seem competitive with new water and disposal of flowback water. It remains unclear how many operators follow a recycling program similar to that of Devon in the Barnett and elsewhere in Texas. Conservatively assuming that twice as many wells as involved in Devon's flowback recycling program have been treated results in 3% of the injected frac water having been treated (~70 thousand AF since 2005). Incorporating the fact that some flowback water was probably used without extensive treatment and not counted toward the figures presented earlier will increase this number. For example, reuse, although it probably depends on the operating company, can be as high as ~200,000 gal per well in Barnett wells with little treatment (M. Mantell, Chesapeake, personal communication, 2010), corresponding to a 6% reuse. Chesapeake does not typically reuse water from the Haynesville (too little and of poor quality). Overall, the recycling effort can be estimated in the 5–10% range in the Barnett and ~0% in the Haynesville.

The industry is bound to make tremendous technological progress in recycling, driven mostly by issues external to the state of Texas. When a critical mass of companies involved in recycling is reached, substantial progress in efficiency and rate is expected. Particularly because of specifics in the Marcellus Shale area, such as limited use of injection wells and municipal wastewater-treatment facilities, the industry will make progress in recycling (as long as there is material to recycle). In this study we assumed that a maximum of 20% of the water used for fracing will be used again.

5.1.2.2 Refracing

How much refracing of wells already fraced is taking place is unclear, and the information is conflicting. Vincent (2010) did a systematic study of restimulation from the origins of hydraulic fracturing and concluded that it works (as documented in the literature) and fails (as not documented as often). However, discussion with operators suggests that very little refracing of recent or future wells will take place. Refracing activities so far have been restricted to wells completed early in the development of the slick-water technology and, thus, may be more common for vertical wells. However, Potapenko et al. (2009, p. 2), looking back at Barnett recompletions, found that despite great success with refracing of vertical wells, little success has come from restimulation of horizontal wells. Gel fracs performed early in the history of the play perhaps somehow may have damaged the formation and that the new water fracs have restored it to its full potential (King, 2010, p. 24). Similarly, it was found that "*Some recent spacing between frac stages in horizontal wells by some operators are so close that it may be very difficult to refracture those wells as all the stages are communicated. Many earlier horizontal wells left large segments between stages unperforated for later refracturing development. Some now also believe that drilling horizontal well laterals close (250 ft.) and not simo-fracturing is leaving gas in place that may not be refractured successfully later on using current technology. Some of us believe that simo-fracturing provides gas today that might have been recovered years later through refracturing.*" (PBSN, Sept. 23, 2008). Simo-fracturing consists of fracing neighboring wells at the same time. However, the same newsletter (PBSN, May 5, 2008; Oct. 5, 2009) states "*We believe most Barnett Shale horizontal wells will be refractured within the first seven years of production.*"

This work assumes that all the possible restimulations have already been done and that there will be no need to refrac newer wells.

5.1.2.3 Infill drilling

Infill drilling takes advantage of the new technologies (horizontal drilling and hydraulic fracturing) that can then be applied to older plays and reservoirs. Infill drilling is an important factor but has no need to be included explicitly as a correcting factor. It is already implicitly part of the methodology.

5.1.2.4 New or Updated Technologies

New or updated technologies that could further decrease reliance on fresh water include use of fluids other than water (propane, N_2, CO_2), sonic fracturing with no added fluid, and other waterless approaches with specialized drilling tools. N_2 fracs may prove effective. Brannon et al. (2009) and van Hoorebeke et al. (2010) described a ~250,000-gal liquid N_2 for a multistage frac job with a 3,000-ft-long lateral. These workers noted that although this kind of frac is not widespread, Marcellus operators may find advantages in using N_2 fracs because of their limited need of water and lack of disposal issues. They went on to note that the Woodford and Barnett Shales present a favorable lithology for application of this technology. Other potential development includes cryogenic nitrogen or CO_2 and high-energy gas fracturing (Zahid et al., 2007). Friehauf and Sharma (2009) discussed the benefits of "energizing" frac fluids with gases such as N_2 or CO_2 (better). Gas addresses the water-trapping problem by creating high gas saturation in the invaded zone and facilitating gas flow. How this different approaches impact total water use is, however, unclear. As the cost of water increases, those methods potentially more expensive than water fracs could become more attractive and receive more attention. Some companies already seem to be using CO_2 fracs in the Barnett and Eagle Ford. Some technologies

limit the amount to be disposed of but do not necessarily reduce the demand on local water resources, for example, using waste heat from compressors to evaporate (but not recover) water.

This work does not account for such technological progress and assumes that all plays will be produced thanks to technologies currently applied on a wide scale.

5.1.3 Conclusions on Fracing Water Use

Overall water use for fracing will increase from the current ~37 thousand AF to a peak of ~120 thousand AF by 2020–2030 (Figure 116). However, uncertainty is large. We assumed no major technological breakthrough in fracing technology and no more than small incremental annual increase in efficiency. Another way to measure uncertainty is to assess the two approaches used (production-based and resource-based approaches). Used independently, these would differ by a factor of two in terms of water use. In addition, there are still several other potential gas accumulations, particularly at larger depths than considered in this study—for example, Cotton Valley and pre-Pearsall Formations in South Texas (Ewing, 2010), Travis Peak potential tight-gas resources downdip of the current play (Li and Ayers, 2008), and Silurian, Ordovician (Simpson Group), or even Cambrian targets in the Delaware Basin or the Permian Basin (Dutton et al., 2005a)—but which are all too speculative to be included in this study. Production from these formations would mean that water use, instead of decreasing after the peak of ~120 thousand AF would stay at that level or possibly higher for a longer period of time.

Table 42. Flowback volume characteristics.

	Frac Water Volume (Mgal)	Flowback @ 10 Days (Mgal)	Ultimate Produced Water (Mgal)	Recovery Ratio
Barnett	3.8	0.6	11.730	3.1
Haynesville	5.5	0.25	4.475	0.9
Fayetteville	4.2	0.5	0.980	0.25
Marcellus	5.5	0.5	0.700	0.15

Source: M. Mantell, GWPC Annual UIC Conference, Austin, TX, January 26, 2010

Table 43. Compilation of published Texas oil and gas reserves

	Oil (Bbbl)	Gas (Tcf)	Source
Proved Reserves			
Texas	5.122 4.56	72.1 81.8	EIA (2008, Tables 4 & 5) RRC website (2010, data from 2008)
Districts 4+2 (South TXs)	0.092	0.00 Shale 10.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
District 6 (East TX)	0.16	0.16 Shale 11.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Districts 8+8A+7C (~PB)	4.30	0.04 Shale 13.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Districts 5+9+7B (~FWB)	0.23	21.4 Shale 26.8 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
District 10 (~An. B)	0.05	0.00 Shale 6.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Undiscovered Recoverable Resources (Mean)			
Permian Basin, including New Mexico	0.75 Conv. 0.51 Cont. 1.26 Total	5.20 Conv. 0.26 Tight 35.13 Shale 40.58 Total	USGS – NOGA website 2010*
Anadarko (TX+OK+KS)	0.40 Conv. 0.00 Cont. 0.40 Total	14.20 Conv. 0.00 Tight 0.00 Shale 14.20 Total	USGS – NOGA website 2010*
Fort Worth Basin (>Texas)	0.10 Conv. 0.00 Cont. 0.10 Total	0.47 Conv. 0.00 Tight 26.23 Shale 26.70 Total	USGS – NOGA website 2010*
Western Gulf Coast (TX+LA)	2.29 Conv. 1.09 Cont. 3.38 Total	68.09 Conv. 2.63 Tight 0.00 Shale 70.72 Total	USGS – NOGA website 2010*
East Texas**	2.76 Conv. 0.00 Cont. 2.76 Total	0.00 Conv. 0.00 Tight 0.00 Shale 0.00 Total	USGS – NOGA website 2010*

*NOGA website http://energy.cr.usgs.gov/oilgas/noga/assessment_updates.html (updates)
**The only information for East Texas is commingled with Mississippi salt-basin data
Conv. = conventional; Cont. = continuous

Table 44. Compilation of published reserves for oil and gas shales and tight formations

Play	OOIP/OGIP (Tcf/Bbbl)	Produced Amount	Total Recoverable Reserves (variable unit)	Source
Barnett		7 Tcf*		RRC website – to 2009
		8.2 Tcf 23.6 million bbl		PBSN (Nov.1, 2010) to 09/01/2010
	250 Tcf		50-60 Tcf	
			33 Tcf	EIA (2008) from website
	327 Tcf		44 Tcf	U.S. DOE (2009, p. 17)
			26.2 / 1.0 Bbbl NGL	Coleman (2009, Table 3) - Pollastro (2007)
			36 Tcf (low); 59 Tcf (BG); 102 Tcf (high)	Mohr and Evans (2010)
Eagle Ford			150 / 25 Bbbl	Basin O&G, Nov. 2010, p. 10
			226 Tcfe**	Cusack et al. (2010, p. 172)
Haynesville (TX+LA)			Up to 100 Tcf	Spain and Anderson (2010)
	717 Tcf		251	U.S. DOE (2009, p. 17)
			73 Tcf (low); 131 Tcf (BG); 250 Tcf (high)	Mohr and Evans (2010)
			60 Tcf (for TX?)	Hammes (2009)
Bossier (TX+LA)			100 Tcf	Hanson and Lewis (2010)
Permian Basin (Woodford, Barnett, Wolfberry)			35 Tcf / 1.3 Bbbl oil+NGL	Coleman (2009, Table 3)
Woodford – Delaware Basin			Undisc.: 15.1 Tcf / 0.30 Bbbl NGL	Schenk et al. (2008)
Barnett – Delaware Basin			Undisc.: 17.2 Tcf / 0.34 Bbbl NGL	Schenk et al. (2008)
Woodford+Barnett – Midland B.			Undisc.: 2.8 Tcf / 0.11 Bbbl NGL	Schenk et al. (2008)
Spraberry			Undisc.: 0.26 Tcf /0.53 Bbbl Oil+NGL	Schenk et al. (2008)

*Through 2009, RRC website http://www.rrc.state.tx.us/barnettshale/index.php
**Undisc. = Undiscovered (mean); BG = Best Guess
1 bbl oil = 5.9 Mcf or 1 Bbbl = 5.9 Tcf

Table 45. Compilation of published operational characteristics for oil and gas shales and tight formations

Play	OGIP (Bcf/section)	EUR (Bcf/well)	IP (MMcfd)	Source
Barnett	140	2.65 Bcf		F. Wang, pers. comm. (2010)
	65			U.S. DOE (2009, p. 17)
	100150			Vassilellis et al. (2010)
		3.3 Bcf (core)		XTO Energy (2009)
		3.0 Bcf		Mantell (2010)
		3.0 Bcf (Hor.) 0.74 Bcf (Ver.)		Baihly et al.(2010) at 30 years
		1.25 Bcf		Jarvie (2009) at 30 years
		1.16 Bcf Hor.		SPEE-Anonymous (2010)
Haynesville	150–170	7.5 (4.5-8.5)		F. Wang, pers. comm. (2010)
	160–240			Vassilellis et al. (2010)
		3-6 Bcf	Up to 30	Spain and Anderson (2010, p. 657)
		6.5 Bcf		Hammes (2009)
		6.5 Bcf		XTO Energy (2009)
		6.5 Bcf		Mantell (2010)
	80			U.S. DOE (2009, p. 17)
		5.9 Bcf		Baihly et al. (2010) at 30 years
		3.42 Bcf		Jarvie (2009) at 30 years
		2.6 Bcf		SPEE-Anonymous (2010)
Eagle Ford	140–212			Cusack et al. (2010)
	40–223	5-6 Bcf		Vassilellis et al. (2010)
		5-6 Bcfe		DrillingInfo (2010)
		3.8 Bcf		Baihly et al. (2010) at 30 years
Pearsall	80–120			Vassilellis et al. (2010)
Woodford		3.8 Bcf		XTO Energy (2009)
Cotton Valley		1.9 Bcf (Hor.) 1.0 Bcf (Vert.)		Baihly et al.(2010) at 30 years
Cleveland (Hor.)		0.8 Bcf (Hor.) ~0.5 Bcf (Ver.)		Baihly et al.(2010) at 30 years

Note: 1 section = 640 acres = 1 mi^2.

Table 46. Summary description of parameters used in water-use projections (shale-gas plays)

	Barnett	**Haynesville**	**Eagle Ford**	**Bossier**	**Haynes. West**	**Pearsall**	**Woodford/Barnett Delaware Basin**
Resource-based Approach							
County Coverage	80%	80%	80%	80%	80%	60%	80%
Lateral Spacing (ft)	1000	1000	1000	1000	1000	1000	1000
Intensity-Mgal/1000ft	H.: 1.0	H.: 1.1	H.: 1.25	H.: 1.1	H.: 1.1	H.: 1.0	H.: 1.0
Uncorrected total water use (Th. AF)	1,020	440	1,513	225	37	358	434
Production-based Approach							
Play EUR (Tcf Equ.) from 2010 to 2060	61 52	44 28	250 161	33 21	2.2	25	25
Peak year after start End year after start (county level)	+8 +30	+11 +50	+16 +70	+10 +50	+15 +45	+15 +70	+15 +70
Overall peak year	2015	2031	2035	2020	2033	2031	2031
Average well EUR (BCF)	H.: 2 (core) H.: 1 (non-c.) V.: 0.8	H.: 2	H.: 1.3	H.: 1.2	H.: 2	H.:1.5	H.: 1.5
Average water use /well (Mgal)	3.3	6.1	6.2	3.3	6.1	3.3	3.3
Uncorrected total water use (Th. AF)	457	278	1897	356	23	193	193
Number of wells estimate	59,636	14,712	99,120	19,013	1,255	19,040	19,040
Reuse / Recycling	-1% / year <20%	-0.5% / year <3%	-1% / year <20%	-1% / year <20%	-0.5% / year <3%	-1% / year <20%	-1% / year <20%
Total water use (final results in AF)	750	426	1070	191	36	223	270

Table 47. Summary description of parameters used in water-use projections (tight formations)

	Anadarko Basin	**East Texas**	**Wolfberry**	**Gulf Coast**	**Other Permian Basins**
Resource-based Approach					
County coverage	20%	150%	80%	8%	8%
Lateral spacing (ft)	1000	n/a	n/a	n/a	n/a
Intensity (Mgal/1000 ft)	450	n/a	n/a	n/a	n/a
Vertical well (Mgal)	0.4	0.9	1.0	0.5	0.8
Uncorrected total water use (Th. AF)	50	189	314	76	145
Production-based approach					
Play EUR (Tcf Equ.) from 2010 to 2060	10	16	1070 Bbbl	11	15
Peak year after start End year after start (county level)	+6 +22	+12 +50	+15 +50	+18 +60	+8 +35
Overall peak year	2015	2022	2023	2027	2017
Average well EUR (BCF)	H : 1.2 (50%) V. : 0.6 (50%)	H.: 2 (25%) V. : 0.5 (75%)	H. : n/a V. : 0.06 MMbbl	H.: n/a V. : 0.4	H.: n/a V. : 0.3
Average water-use /well (Mgal)	H.: 1.3 V.: 1	H.: 3 V.: 0.9	H.: n/a V.: 0.9	H.: n/a V.: 0.5	H.: n/a V.: 0.8
Uncorrected total water use (Th. AF)	46	140	94	61	182
Number of wells estimate	13,197	33,961	34,031	33,650	71,513
Reuse / Recycling	-1% / year <20%	-1% / year <20%	-1% / year <20%	0%	-1% / year <20%
Total water use (final results in AF)	49	165	283	78	150

Table 48. Projected water use in the Barnett Shale (Fort Worth Basin)

County	2010*	2020	2030	2040	2050	2060
	AF					
Archer	0	1,618	1,292	369	0	0
Bosque	913	2,547	1,065	0	0	0
Clay	634	3,731	1,663	0	0	0
Comanche	429	2,524	1,125	0	0	0
Cooke	101	282	118	0	0	0
Coryell	0	1,793	1,140	263	0	0
Dallas	620	769	271	0	0	0
Denton	1,674	587	0	0	0	0
Eastland	0	1,127	1,157	386	0	0
Ellis	325	235	63	0	0	0
Erath	2,017	2,500	882	0	0	0
Hamilton	190	1,118	498	0	0	0
Hill	1,008	1,249	441	0	0	0
Hood	1,720	990	215	0	0	0
Jack	1,835	1,706	535	0	0	0
Johnson	3,308	1,537	241	0	0	0
McLennan	0	1,380	680	62	0	0
Montague	539	3,174	1,415	0	0	0
Palo Pinto	446	2,627	1,171	0	0	0
Parker	4,003	1,787	153	0	0	0
Shackelford	0	1,121	1,151	384	0	0
Somervell	771	443	96	0	0	0
Stephens	0	1,854	1,178	272	0	0
Tarrant	3,147	1,104	0	0	0	0
Wise	4,220	1,961	308	0	0	0
Young	0	563	578	193	0	0
Total (Th. AF)	**27.9**	**40.3**	**17.4**	**1.9**	**0.0**	**0.0**

*Projected value, not actual observed water use (see Current Water Use Section)MohrDataBarnett_3.xls FinalReport-Sept.10.xls

Table 49. Projected water use in the Haynesville Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Angelina	0	426	534	367	200	33
Gregg	0	245	435	307	179	51
Harrison	344	2,506	1,848	1,211	574	0
Marion	0	413	517	356	194	32
Nacogdoches	0	1,683	1,582	1,055	527	0
Panola	308	2,242	1,654	1,083	513	0
Rusk	0	1,841	1,730	1,153	577	0
Sabine	0	856	804	536	268	0
San Augustine	221	1,613	1,189	779	369	0
Shelby	314	2,284	1,685	1,104	523	0
Upshur	0	440	781	551	321	92
Total (Th. AF)	**1.2**	**14.5**	**12.8**	**8.5**	**4.2**	**0.2**
Leon	0	57	201	183	96	9
Freestone	0	69	243	221	116	11
Total (Th. AF)	**0.0**	**0.4**	**1.4**	**1.2**	**0.6**	**0.1**

MohrDataHaynesville.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 50. Projected water use in the Bossier Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Nacogdoches	116	2,379	1,599	1,083	567	52
Sabine	210	1,411	949	643	337	31
San Augustine	213	1,432	962	652	342	31
Shelby	302	2,028	1,363	923	484	44
Total (Th. AF)	**0.8**	**7.3**	**4.9**	**3.3**	**1.7**	**0.2**

MohrDataHaynesv.TemplateBossier.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 51. Projected water use in the Eagle Ford Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Atascosa	0	1,443	2,273	1,836	1,399	962
Austin	0	48	256	279	221	163
Brazos	0	519	1,132	922	712	503
Burleson	0	594	1,295	1,055	816	576
Colorado	0	859	1,874	1,527	1,180	833
DeWitt	0	1,067	1,681	1,357	1,034	711
Dimmit	218	2,155	2,327	1,852	1,377	902
Fayette	0	842	1,838	1,497	1,157	817
Frio	0	82	438	477	378	278
Gonzales	0	79	420	458	363	267
Grimes	0	59	314	342	271	200
Karnes	0	1,113	1,350	1,080	810	540

County	2010*	2020	2030	2040	2050	2060
	AF					
La Salle	242	2,390	2,581	2,054	1,528	1,001
Lavaca	0	571	1,776	1,591	1,245	899
Lee	0	47	249	272	215	159
Leon	0	635	1,976	1,771	1,386	1,001
Live Oak	0	79	420	458	363	267
McMullen	0	1,689	2,047	1,638	1,228	819
Madison	0	278	865	775	607	438
Maverick	0	430	1,338	1,199	938	678
Washington	0	366	1,139	1,021	799	577
Webb	138	1,369	1,478	1,177	875	573
Wilson	0	473	1,473	1,320	1,033	746
Zavala	0	434	1,352	1,211	948	685
Total (Th. AF)	**0.6**	**17.6**	**31.9**	**27.2**	**20.9**	**14.6**

MohrDataHaynesv.TemplateEagleFord.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 52. Projected water use in the Woodford and Barnett Shales in the Delaware Basin

County	2010*	2020	2030	2040	2050	2060
	AF					
Crane	0	20	63	50	39	28
Culberson	0	1,324	4,120	3,230	2,528	1,826
Pecos	0	666	2,071	1,624	1,271	918
Reeves	0	893	2,778	2,179	1,705	1,231
Ward	0	44	136	107	84	60
Winkler	0	30	92	72	56	41
Total (Th. AF)	**0.0**	**3.0**	**9.3**	**7.3**	**5.7**	**4.1**

MohrDataHaynesv.TemplateDelawareWoodford+Barnett.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 53. Projected water use in the Pearsall Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Atascosa	0	244	757	594	465	336
Dimmit	0	470	1,463	1,147	898	648
Frio	0	98	306	240	188	136
La Salle	0	521	1,622	1,272	995	719
Live Oak	0	94	294	231	180	130
McMullen	0	405	1,261	989	774	559
Maverick	0	458	1,427	1,119	876	632
Webb	0	48	149	117	91	66
Zavala	0	116	360	283	221	160
Total (Th. AF)	**0.0**	**2.5**	**7.6**	**6.0**	**4.7**	**3.4**

MohrDataHaynesv.TemplatePearsall.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 54. Projected water use in the Wolfberry play

County	2010*	2020	2030	2040	2050	2060
	AF					
Andrews	71	404	383	232	97	0
Borden	42	242	229	139	58	0
Dawson	42	241	228	139	58	0
Ector	42	242	229	139	58	0
Gaines	71	405	384	233	97	0
Glasscock	171	975	924	561	235	0
Howard	172	980	929	564	236	0
Irion	197	1,124	1,065	647	271	0
Martin	172	977	926	562	235	0
Midland	171	974	923	560	234	0
Reagan	223	1,273	1,206	732	306	0
Schleicher	22	128	121	74	31	0
Sterling	44	248	235	143	60	0
Upton	234	1,336	1,266	768	321	0
Total (Th. AF)	**1.7**	**9.5**	**9.0**	**5.5**	**2.3**	**0.0**

MohrDataHaynesv.TemplateWolfberry.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 55. Projected water use in East Texas tight-gas plays

County	2010*	2020	2030	2040	2050	2060
	AF					
Anderson	0	24	83	66	41	15
Cass	0	52	66	46	25	4
Cherokee	23	254	288	188	89	0
Freestone	636	856	670	439	208	0
Gregg	132	177	138	91	43	0
Harrison	900	532	395	259	123	0
Henderson	0	259	327	225	123	21
Limestone	279	375	293	192	91	0
Marion	23	252	210	138	65	0
Nacogdoches	321	321	245	160	76	0
Panola	805	476	354	232	110	0
Robertson	287	606	487	319	151	0
Rusk	51	563	468	307	145	0
Shelby	0	228	288	198	108	18
Smith	0	103	130	90	49	8
Upshur	0	163	206	141	77	13
Total (Th. AF)	**3.5**	**5.2**	**4.6**	**3.1**	**1.5**	**0.1**

MohrDataHaynesv.TemplateEastTexas.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 56. Projected water use in Anadarko Basin tight formations

County	2010*	2020	2030	2040	2050	2060
	AF					
Hansford	74	675	61	0	0	0
Hemphill	694	364	33	0	0	0
Hutchinson	6	59	6	0	0	0
Lipscomb	123	507	46	0	0	0
Ochiltree	73	671	61	0	0	0
Roberts	183	447	41	0	0	0
Sherman	7	61	6	0	0	0
Wheeler	697	365	33	0	0	0
Total (Th. AF)	**1.9**	**3.1**	**0.3**	**0.0**	**0.0**	**0.0**

MohrDataHaynesv.TemplateAnadarko.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 57. Projected water use in the South Gulf Coast Basin tight-gas plays

County	2010*	2020	2030	2040	2050	2060
	AF					
Aransas	9	17	22	16	11	5
Bee	23	47	58	43	29	14
Brazoria	37	75	94	70	46	21
Brooks	25	49	62	46	30	14
Calhoun	17	33	42	31	21	10
Cameron	25	50	62	46	30	14
Colorado	25	51	64	48	31	15
DeWitt	24	47	60	44	29	14
Duval	47	94	118	87	57	27
Fort Bend	23	46	58	43	28	14
Goliad	22	45	56	42	27	13
Hidalgo	42	83	105	78	51	24
Jackson	22	45	56	42	28	13
Jim Hogg	30	60	75	56	37	17
Jim Wells	23	45	57	42	28	13
Karnes	20	40	50	37	24	11
Kenedy	38	76	95	71	46	22
Kleberg	25	49	62	46	30	14
La Salle	39	77	97	72	47	22
Lavaca	25	51	64	47	31	15
Live Oak	28	56	70	52	34	16
McMullen	30	60	75	56	37	17
Matagorda	31	61	77	57	37	18
Nueces	22	45	56	42	28	13
Refugio	21	42	53	39	26	12
San Patricio	18	37	46	34	22	11
Starr	32	64	79	59	39	18
Victoria	23	46	58	43	28	14
Webb	88	177	222	165	108	51

County	2010*	2020	2030	2040	2050	2060
	AF					
Wharton	29	57	72	53	35	17
Willacy	16	31	39	29	19	9
Zapata	27	55	68	51	33	16
Total (Th. AF)	**0.9**	**1.8**	**2.3**	**1.7**	**1.1**	**0.5**

MohrDataHaynesv.TemplateGulfCoast.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 58. Projected water use in the Permian Basin tight formations

County	2010*	2020	2030	2040	2050	2060
	AF					
Andrews	231	509	297	85	0	0
Borden	68	157	91	26	0	0
Crane	121	277	161	46	0	0
Crockett	53	123	72	21	0	0
Dawson	68	156	91	26	0	0
Ector	265	328	191	55	0	0
Gaines	114	263	153	44	0	0
Garza	68	156	91	26	0	0
Glasscock	138	316	184	53	0	0
Howard	139	318	185	53	0	0
Loving	103	236	138	39	0	0
Lynn	68	157	91	26	0	0
Martin	342	285	166	48	0	0
Midland	341	284	166	47	0	0
Mitchell	68	157	92	26	0	0
Pecos	37	86	50	14	0	0
Reagan	446	371	217	62	0	0
Reeves	400	917	535	153	0	0
Scurry	69	158	92	26	0	0
Sterling	70	161	94	27	0	0
Sutton	108	248	145	41	0	0
Terrell	45	103	60	17	0	0
Terry	68	155	90	26	0	0
Upton	525	454	265	75	0	0
Val Verde	22	51	30	9	0	0
Ward	126	289	168	48	0	0
Winkler	133	307	179	51	0	0
Yoakum	61	140	81	23	0	0
Total (Th. AF)	**4.3**	**7.2**	**4.2**	**1.2**	**0.0**	**0.0**

MohrDataHaynesv.TemplatePB-TG.xls

*Projected value, not actual observed water use (see Current Water Use Section)

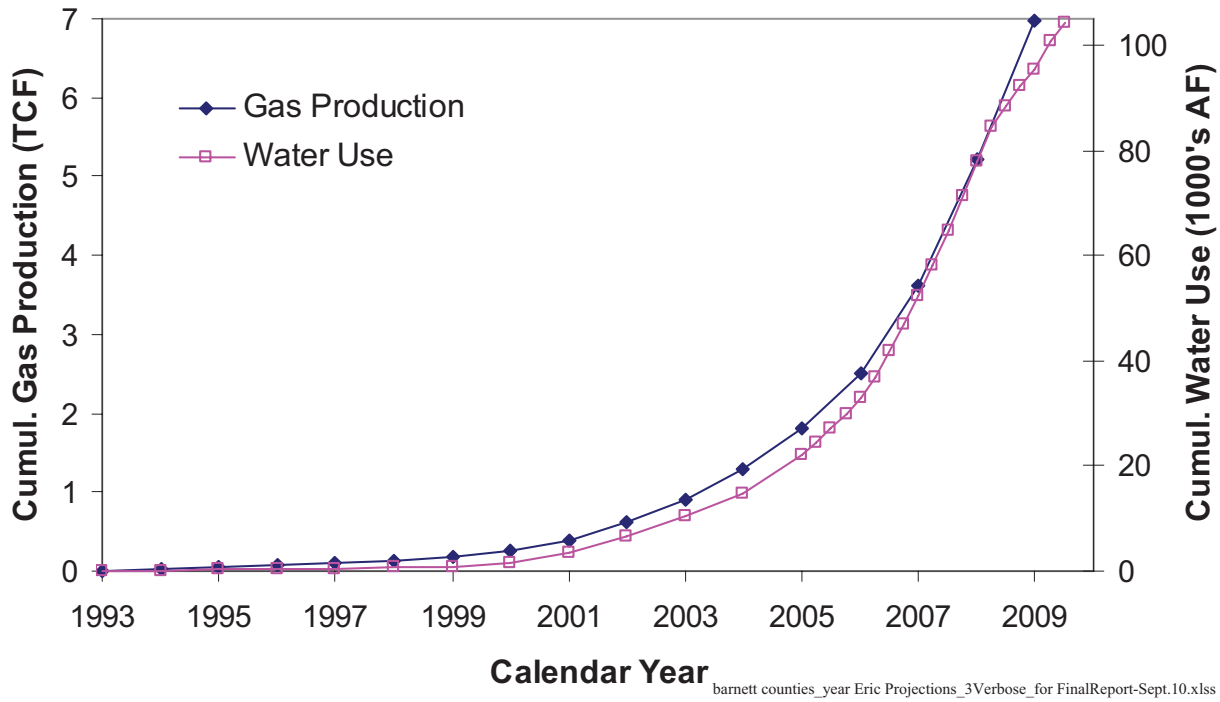
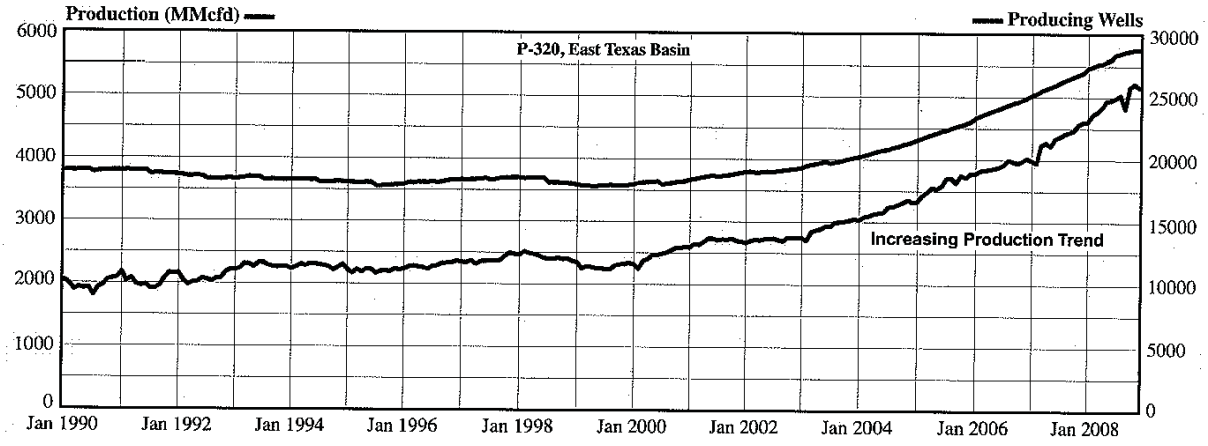
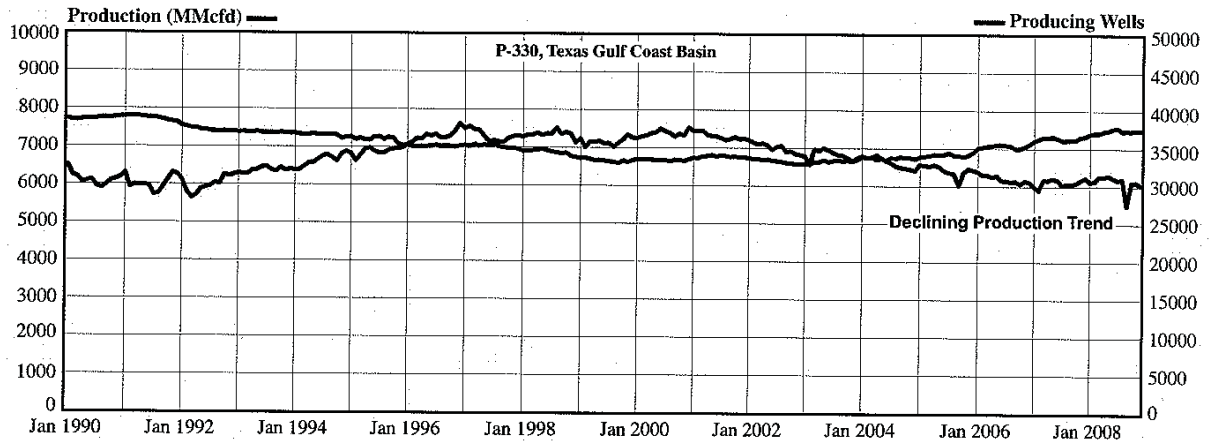


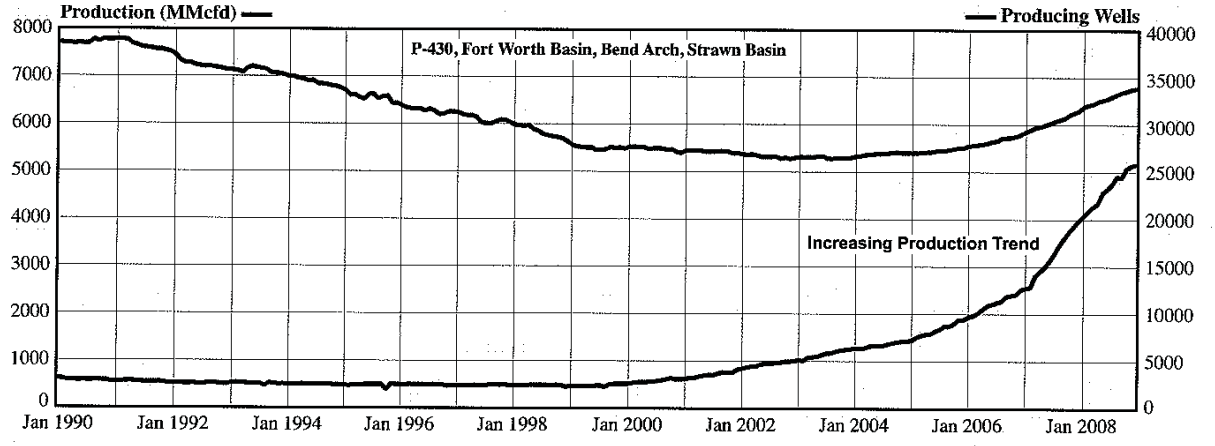
Figure 114. Cumulative gas production and water use in the Barnett Shale play from the origins



Source: PGC (2009); raw data from IHS Energy
Note: The most irregular curve represents gas production; a 1000-MMcfd unit in the production axis corresponds to 0.365 Tcf

Figure 115. Monthly wet-gas production and number of producing oil and gas wells (1990–2008)





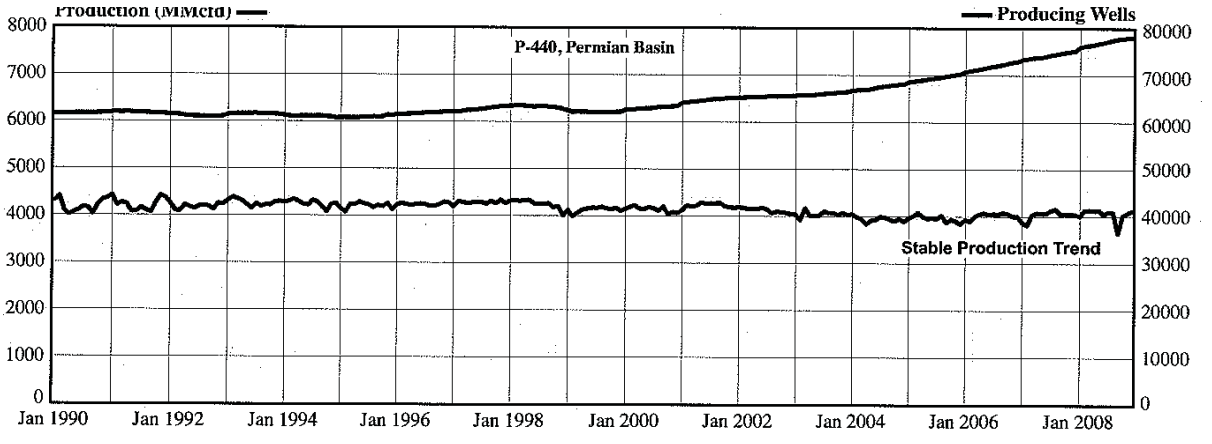


Figure 115. Monthly wet-gas production and number of producing oil and gas wells (1990–2008) (continued)

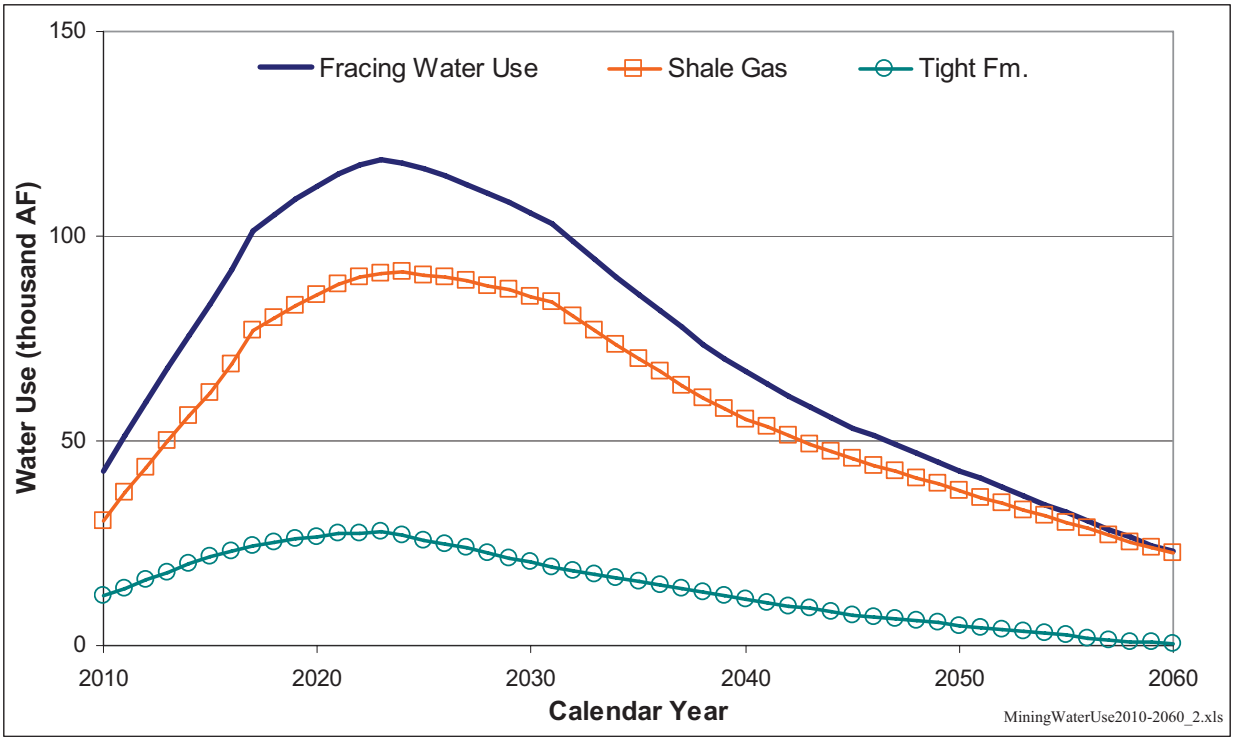


Figure 116. Projected state fracing water use

5.2 Conventional Oil and Gas

Conventional oil and gas, although beyond their peak production, are likely to remain significant for many decades as operators assess and put online new reservoirs. After peak oil in Texas in the early 1970s, the following years showed a slow, more or less linear decrease in production (despite an increase in producing wells). Starting in the late 1990s, though, a graph shows a clear leveling off of the decrease (Figure 117), one section of which can be used to extrapolate future production (Figure 118). Much anecdotal evidence suggests that conventional oil and gas resources in Texas are far from being exhausted. For example, Ewing (2010) listed several likely deep plays (>10,000 ft) in South Texas equivalent to productive formations in East Texas. And operators in the Permian Basin still have to explore for the gas that may lie deeper than current production horizons. As described earlier, USGS oil and gas assessments evaluate the resource that is deemed to be technically recoverable using current and projected techniques. Reserves are defined as a subset of the resources that can be produced economically. The USGS-based National Oil and Gas Assessments (NOGA) is tasked to evaluate those *undiscovered* petroleum resources. NOGA divides the continental U.S. into many provinces, including "West Gulf," "East TX, LA-MS Salt Basins," "Bend Arch-Fort Worth Basin," "Permian Basin," and "Marathon Thrust Belt." Except for the much smaller last province, all four other provinces go largely beyond Texas. The latest complete assessment of the U.S. was made in 1995, although updates of the assessment of some provinces were made very recently.

5.2.1 Water and CO_2 Floods

Conventional oil and gas production use water for two purposes: drilling and EOR. As seen in the current water-use section, water use for waterfloods has been decreasing steadily, and we assume that it will keep making up a smaller and smaller fraction of fluid injected for waterfloods. Fresh water use has been declining strongly in the past decades, and we expect the trend to continue (Figure 119). The general trend of oil production in West Texas has been one of more or less continuous decline since its peak in the early 1970s. Galusky (2010) produced what we think are relatively accurate numbers for the Permian Basin (~10 Bbbl to 2060). Schenk et al. (2008) estimated undiscovered resources of conventional oil in the Permian Basin at 747 million barrels. A study by the consulting firm ARI (Kuuskraa and Ferguson, 2008, Table 1) reports that Texas (including that portion of the Permian Basin in New Mexico) has >200 Bbbl of OOIP of which ~70 Bbbl is conventionally recoverable (primary and secondary recovery processes), an arguably optimistic projection. For comparison, Texas has produced ~60 Bbbl of oil since the origins.

Dutton et al. (2005a) presented a comprehensive study of all known oil and gas fields in the Permian Basin and included a section on production forecast to 2015. The lack of full overlap between the Permian Basin and Districts 08 and 8A (New Mexico had 15.6% of cumulative production through 2000, Dutton et al., 2005a, p. 351) carries some uncertainty but the error introduced by assuming the Permian Basin and RRC Districts 08 and 8A coincide is small compared to the other assumptions used in this section. Dutton et al. (2005a) projected a production of 3.25 Bbbl of oil through 2015 from which the 1.9 Bbbl produced through 2010 (since the publication of the Dutton et al., 2005a report) must be deducted yielding 1.35 Bbbl to be produced to 2015. This is consistent with Galusky (2010)'s projections at 1.44 Bbbl from 2011 to 2015. Both workers have in common the slow decline of conventional oil production at a similar rate.

The slow pace of this decline (~2% per year) reflects the steady increase in EOR production techniques (waterfloods and CO_2 floods). The general pattern of declining oil production has occurred through high-price as well as low price-intervals. It would thus seem reasonable to project this gradual decline through the forecast period of this study (2010– 2060). Oil drilling and completion activities and oil production are expected to be sustained at slowly declining levels in West Texas over the next 50 years. It is projected that EOR production methods will be responsible for 70% or more of total oil production by 2020 and beyond. Although EOR production requires copious quantities of water to sustain oil reservoir pressures, fresh water is expected to decline in use relative to brackish and saline (recycled produced) waters. Total brackish and saline water use is thought to have essentially peaked near the present estimated figure of ~38.5 thousand AF/yr and is then expected to decline over the coming decades. In contrast, total fresh-water use is expected to continue to decline from the present estimated figure of ~10,000 ac-ft/yr to less than half this level by 2020. In this study we did not investigate the possibility of having extensive waterfloods in the Gulf Coast area or elsewhere in the state. We did not include the real potential for extensive CO_2 floods as it is not clear whether operators would use a WAG technique with concomitant water use or simply inject CO_2 (which might be in abundance in the future, thanks to the presence of many coal-fired power plants along the Gulf).

Table 59 summarizes our findings per county. Projections of overall water use, estimated at ~8 thousand AF in 2010, is decreasing through time because of the built-in assumption of decreased fresh water use for the purpose of waterflood and other recovery processes.

Going back to historical reports (for example, Torrey, 1967) is insightful in the sense that it allows comparison of projections with actual production and water use. The 1967 report author makes the correct statement (p. 2) that no reasonable alternative but to extrapolate currents can be made in a 50-year projection period. The report predicts average water use in the 1990–2000 decade of ~220 thousand AF for much smaller oil production than actually occurred. Included in their water use is all nonproduced waters, of which it is unclear how much is fresh or brackish. The approach was to compute oil reserves amenable to water injection for pressure maintenance or waterflooding (25% increasing to 50% of projected production in 2010) and to apply a multiplier (average of 8.2 bbl of water used to produce 1 bbl of oil) corrected by the amount of produced water used (typically 10%– 20%, that is, most of water is makeup water, although the quality is not described).

5.2.2 Drilling

In general, drilling and completion activities are much more sensitive to short-term price cycles than production. Periods of relatively high oil prices tend to incentivize and support a proportionally greater level of drilling activity than do periods of low prices. It would be virtually impossible to predict oil prices many years into the future with any level of real confidence. Projections of water use for drilling are thus more perilous than price or production projections. Nevertheless, it seems reasonable to project a gradual decline in fresh water use for oil drilling in the coming decades, Even as oil fields become depleted, an increase in drilling activity for oil can be expected because of the renewed interest in plays similar to the Wolfberry in the Permian Basin and because of an increased interest in waterflooding, requiring drilling of new wells. This increase in drilling is likely to be more than balanced by a decrease in fresh-water use as the industry uses more and more brackish and saline water. Galusky (2010) proposed to assume that the fresh water use for drilling in the Permian Basin (which is more

densely drilled than the rest of Texas) will stay relatively stable until 2020, and will gradually decrease below about half its present level by 2060. We assume that the pattern is applicable to the whole state. Despite the general decrease of fresh-water use in oil production, it is likely that the water use for drilling will keep increasing for the next few years because of shale-gas activity. The amount of fresh water used in drilling shale gas wells is variable and a function of the play (Section 4.2.2). Including water use from shale-gas activity yields a peak of 13 thousand AF within the current decade (Figure 120).

Table 59. County-level fresh and brackish water-use projections for waterflood

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
State Total	**7.87**	**2.39**	**1.49**	**1.29**	**1.12**	**0.96**	**29.91**	**31.49**	**31.93**	**28.34**	**24.58**	**21.26**
Anderson	0.008	0.002	0.002	0.001	0.001	0.001	0.031	0.033	0.033	0.029	0.025	0.022
Andrews	0.384	0.117	0.073	0.063	0.055	0.047	1.457	1.534	1.556	1.381	1.197	1.036
Archer	0.003	0.001	0.001	0.000	0.000	0.000	0.010	0.011	0.011	0.010	0.009	0.007
Atascosa	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.003	0.003	0.002	0.002	0.002
Baylor	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001
Borden	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Brown	0.005	0.001	0.001	0.001	0.001	0.001	0.018	0.019	0.019	0.017	0.015	0.013
Callahan	0.018	0.005	0.003	0.003	0.003	0.002	0.067	0.071	0.072	0.064	0.055	0.048
Camp	0.003	0.001	0.001	0.000	0.000	0.000	0.010	0.011	0.011	0.010	0.008	0.007
Carson	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001
Clay	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.004	0.004	0.003	0.003
Cochran	0.005	0.002	0.001	0.001	0.001	0.001	0.020	0.021	0.021	0.019	0.016	0.014
Coke	0.109	0.033	0.021	0.018	0.016	0.013	0.416	0.438	0.444	0.394	0.342	0.296
Coleman	0.021	0.006	0.004	0.003	0.003	0.003	0.080	0.084	0.085	0.076	0.066	0.057
Comanche	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.002	0.002	0.001	0.001	0.001
Concho	0.108	0.033	0.021	0.018	0.015	0.013	0.412	0.434	0.440	0.390	0.338	0.293
Cooke	0.004	0.001	0.001	0.001	0.001	0.001	0.016	0.017	0.017	0.015	0.013	0.012
Cottle	0.007	0.002	0.001	0.001	0.001	0.001	0.026	0.027	0.027	0.024	0.021	0.018
Crane	0.027	0.008	0.005	0.004	0.004	0.003	0.101	0.106	0.108	0.096	0.083	0.072
Crockett	0.007	0.002	0.001	0.001	0.001	0.001	0.025	0.026	0.027	0.024	0.021	0.018
Crosby	0.228	0.069	0.043	0.037	0.032	0.028	0.866	0.912	0.925	0.821	0.712	0.616
Culberson	0.033	0.010	0.006	0.005	0.005	0.004	0.127	0.134	0.135	0.120	0.104	0.090
Dawson	0.039	0.012	0.007	0.006	0.005	0.005	0.146	0.154	0.156	0.139	0.120	0.104

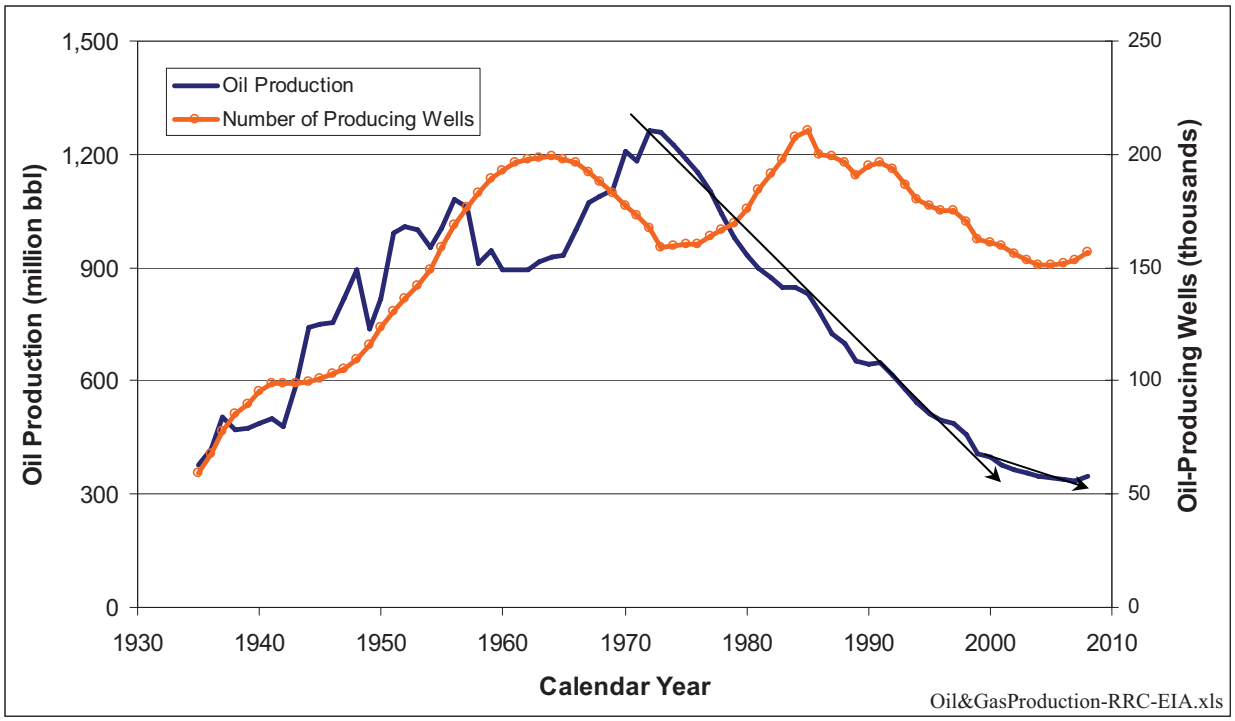
County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Dickens	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Dimmit	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Eastland	0.070	0.021	0.013	0.012	0.010	0.009	0.267	0.281	0.285	0.253	0.219	0.190
Ector	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.075	0.077	0.068	0.059	0.051
Fisher	0.091	0.028	0.017	0.015	0.013	0.011	0.345	0.364	0.369	0.327	0.284	0.245
Floyd	0.031	0.010	0.006	0.005	0.004	0.004	0.119	0.125	0.127	0.113	0.098	0.084
Foard	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.003	0.002	0.002	0.002
Franklin	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.005	0.004	0.004	0.003
Freestone	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.005	0.005	0.004	0.004	0.003
Gaines	0.002	0.001	0.000	0.000	0.000	0.000	0.008	0.009	0.009	0.008	0.007	0.006
Garza	0.011	0.003	0.002	0.002	0.002	0.001	0.042	0.045	0.045	0.040	0.035	0.030
Glasscock	0.085	0.026	0.016	0.014	0.012	0.010	0.324	0.341	0.346	0.307	0.266	0.230
Gray	0.014	0.004	0.003	0.002	0.002	0.002	0.055	0.058	0.058	0.052	0.045	0.039
Grayson	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.005	0.005	0.004	0.004	0.003
Hale	0.271	0.082	0.051	0.045	0.039	0.033	1.031	1.085	1.100	0.977	0.847	0.733
Hansford	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.004	0.004	0.003	0.003
Hartley	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004
Haskell	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.075	0.076	0.068	0.059	0.051
Hockley	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.005	0.005	0.005	0.004	0.003
Hopkins	0.009	0.003	0.002	0.001	0.001	0.001	0.034	0.036	0.036	0.032	0.028	0.024
Howard	0.014	0.004	0.003	0.002	0.002	0.002	0.053	0.056	0.057	0.051	0.044	0.038
Hutchinson	0.004	0.001	0.001	0.001	0.001	0.000	0.015	0.016	0.016	0.014	0.012	0.011
Irion	0.169	0.051	0.032	0.028	0.024	0.021	0.642	0.676	0.685	0.609	0.528	0.456
Jack	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.002	0.002
Jones	0.025	0.008	0.005	0.004	0.004	0.003	0.094	0.099	0.100	0.089	0.077	0.067
Kent	0.006	0.002	0.001	0.001	0.001	0.001	0.023	0.024	0.024	0.022	0.019	0.016
King	1.818	0.553	0.345	0.299	0.258	0.223	6.907	7.271	7.373	6.546	5.676	4.909

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Knox	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.003	0.002	0.002	0.002
Lamb	0.136	0.041	0.026	0.022	0.019	0.017	0.518	0.545	0.553	0.491	0.425	0.368
Leon	0.011	0.003	0.002	0.002	0.002	0.001	0.043	0.045	0.046	0.041	0.035	0.031
Limestone	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.003	0.002	0.002	0.002
Lipscomb	0.003	0.001	0.001	0.000	0.000	0.000	0.011	0.011	0.011	0.010	0.009	0.008
Loving	0.074	0.023	0.014	0.012	0.011	0.009	0.282	0.297	0.301	0.267	0.232	0.200
Lubbock	1.307	0.398	0.248	0.215	0.186	0.160	4.968	5.230	5.303	4.708	4.082	3.531
Lynn	0.207	0.063	0.039	0.034	0.029	0.025	0.785	0.826	0.838	0.744	0.645	0.558
Marion	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.002	0.001
Martin	0.084	0.026	0.016	0.014	0.012	0.010	0.320	0.337	0.342	0.303	0.263	0.227
Maverick	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.004	0.004	0.003	0.003	0.002
McCulloch	0.009	0.003	0.002	0.001	0.001	0.001	0.034	0.035	0.036	0.032	0.028	0.024
McMullen	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.002	0.001	0.001	0.001
Menard	0.250	0.076	0.047	0.041	0.035	0.031	0.948	0.998	1.012	0.899	0.779	0.674
Midland	0.035	0.011	0.007	0.006	0.005	0.004	0.134	0.141	0.143	0.127	0.110	0.095
Mitchell	0.003	0.001	0.001	0.000	0.000	0.000	0.011	0.011	0.011	0.010	0.009	0.008
Montague	0.004	0.001	0.001	0.001	0.001	0.000	0.014	0.015	0.015	0.014	0.012	0.010
Moore	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.004	0.003	0.003	0.002
Motley	0.027	0.008	0.005	0.005	0.004	0.003	0.104	0.110	0.111	0.099	0.086	0.074
Navarro	0.002	0.001	0.000	0.000	0.000	0.000	0.008	0.009	0.009	0.008	0.007	0.006
Nolan	0.045	0.014	0.009	0.007	0.006	0.006	0.171	0.180	0.183	0.162	0.141	0.122
Ochiltree	0.004	0.001	0.001	0.001	0.001	0.000	0.015	0.015	0.016	0.014	0.012	0.010
Oldham	0.003	0.001	0.001	0.001	0.000	0.000	0.012	0.012	0.013	0.011	0.010	0.008
Palo Pinto	0.018	0.005	0.003	0.003	0.003	0.002	0.068	0.071	0.072	0.064	0.056	0.048
Pecos	0.066	0.020	0.012	0.011	0.009	0.008	0.249	0.262	0.266	0.236	0.205	0.177
Potter	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Reagan	0.024	0.007	0.004	0.004	0.003	0.003	0.090	0.094	0.096	0.085	0.074	0.064

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Red River	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.004	0.004	0.003	0.003	0.002
Reeves	0.019	0.006	0.004	0.003	0.003	0.002	0.071	0.075	0.076	0.068	0.059	0.051
Runnels	0.060	0.018	0.011	0.010	0.009	0.007	0.228	0.240	0.243	0.216	0.187	0.162
Rusk	0.011	0.003	0.002	0.002	0.002	0.001	0.044	0.046	0.046	0.041	0.036	0.031
Schleicher	0.030	0.009	0.006	0.005	0.004	0.004	0.112	0.118	0.120	0.106	0.092	0.080
Scurry	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Shackelford	0.046	0.014	0.009	0.007	0.006	0.006	0.173	0.182	0.185	0.164	0.142	0.123
Sherman	0.002	0.001	0.000	0.000	0.000	0.000	0.007	0.007	0.007	0.007	0.006	0.005
Smith	0.004	0.001	0.001	0.001	0.001	0.001	0.016	0.017	0.017	0.015	0.013	0.012
Stephens	1.086	0.330	0.206	0.178	0.154	0.133	4.126	4.343	4.404	3.910	3.390	2.932
Sterling	0.007	0.002	0.001	0.001	0.001	0.001	0.027	0.029	0.029	0.026	0.022	0.019
Stonewall	0.132	0.040	0.025	0.022	0.019	0.016	0.503	0.530	0.537	0.477	0.414	0.358
Sutton	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.006	0.006	0.005	0.005	0.004
Taylor	0.015	0.005	0.003	0.002	0.002	0.002	0.057	0.060	0.061	0.054	0.047	0.041
Terrell	0.106	0.032	0.020	0.017	0.015	0.013	0.401	0.423	0.429	0.380	0.330	0.285
Terry	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.076	0.077	0.068	0.059	0.051
Throckmorton	0.042	0.013	0.008	0.007	0.006	0.005	0.160	0.169	0.171	0.152	0.132	0.114
Titus	0.002	0.001	0.000	0.000	0.000	0.000	0.006	0.007	0.007	0.006	0.005	0.004
Tom Green	0.011	0.003	0.002	0.002	0.002	0.001	0.042	0.045	0.045	0.040	0.035	0.030
Upshur	0.007	0.002	0.001	0.001	0.001	0.001	0.028	0.030	0.030	0.027	0.023	0.020
Upton	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Van Zandt	0.012	0.004	0.002	0.002	0.002	0.001	0.044	0.047	0.047	0.042	0.036	0.032
Ward	0.003	0.001	0.001	0.000	0.000	0.000	0.012	0.012	0.012	0.011	0.009	0.008
Wheeler	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Wichita	0.012	0.004	0.002	0.002	0.002	0.002	0.047	0.050	0.050	0.045	0.039	0.033
Wilbarger	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004
Wilson	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001

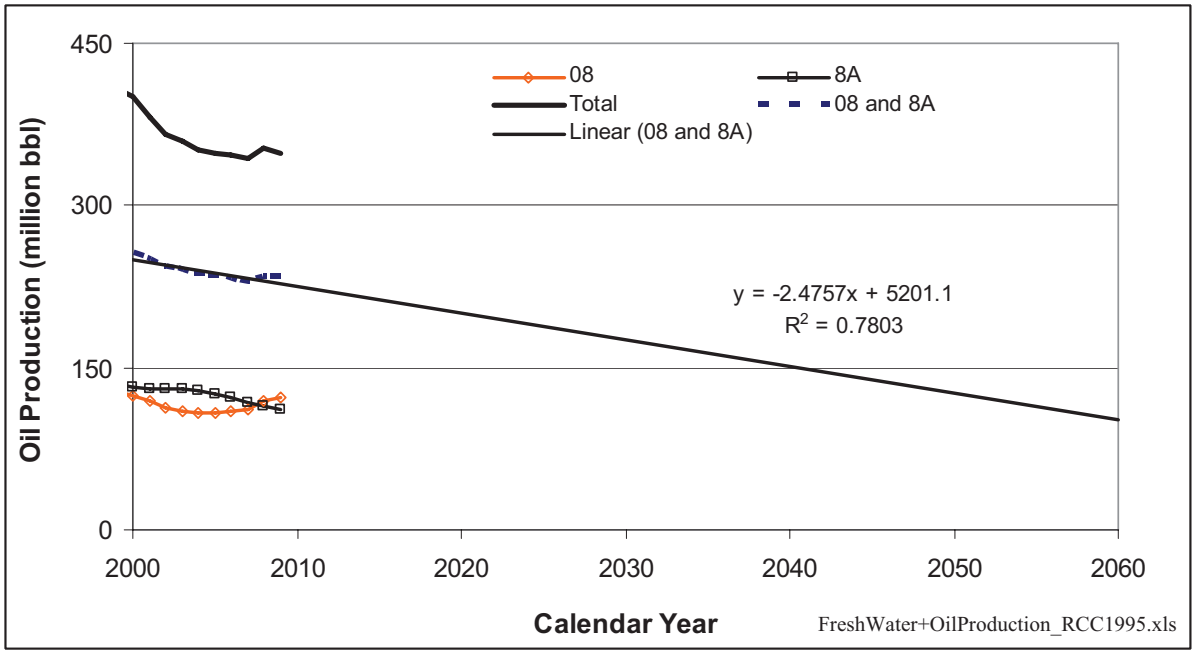
County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Winkler	0.022	0.007	0.004	0.004	0.003	0.003	0.083	0.088	0.089	0.079	0.069	0.059
Wood	0.004	0.001	0.001	0.001	0.001	0.000	0.014	0.015	0.015	0.013	0.011	0.010
Yoakum	0.219	0.067	0.041	0.036	0.031	0.027	0.832	0.875	0.888	0.788	0.683	0.591
Young	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004

InjectionVolume_2002_RRC_+1998-2001_1.xls



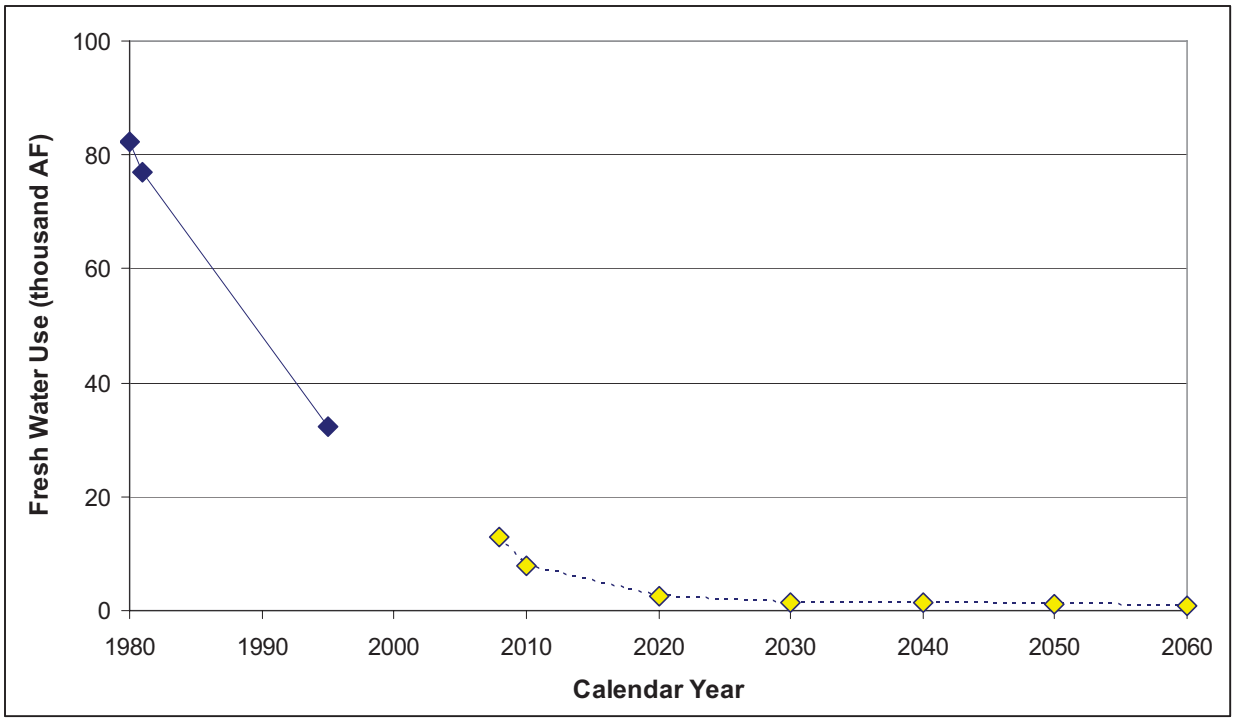
Source: EIA website

Figure 117. Annual oil production in Texas (1936–2009)



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do (historical data)

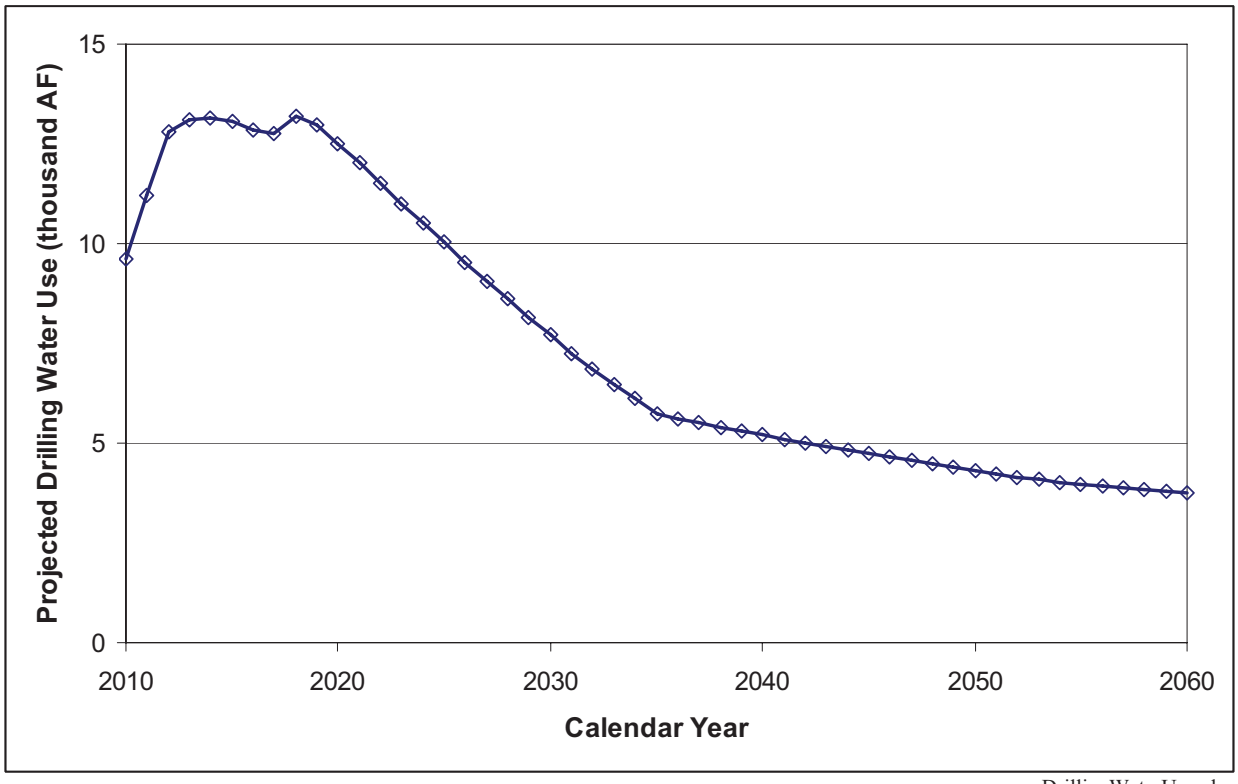
Figure 118. Future annual oil production, Districts 8, 8A, and Texas



Source: RRC (1982) and De Leon (1996) for historical data

Historical Injection 2=fromRRC1982Report.xls

Figure 119. Historical and projected fresh-water use in secondary and tertiary recovery operations



DrillingWaterUse.xls

Figure 120. Projected drilling-water use

5.3 Coal

Coal resources are plentiful in Texas and are unlikely to be exhausted within the next 5 decades at the current average production rate. Kaiser et al. (1980) gave an overview of the lignite resource in Texas and estimated reserves at >6 billion short tons. More recently, Warwick et al. (2002) identified 7.7 billion short tons of Central Texas lignite reserves, excluding resources within coal-mine lease areas. All mines currently in production, except Jewett mine, which is slated to end production around 2025, are assumed to keep producing at a rate similar to the current one. Three Oaks mine came on line recently (2005) after Sandow mine retired. Two new mines will come on line in the next few years: Kosse mine in Limestone County and Twin Oaks mine in Robertson County. Future water-use breakdown for these two mines was estimated from Jewett and Calvert mines, respectively. At the state level, water use is assumed to ramp up from ~25,000 AF/yr to 40,000 AF/yr, mostly because of Three Oak and Twin Oak mines (Figure 121). Other mines' water use remains relatively steady (Figure 122). Results per mine/per county are listed in Table 60. Robertson County exhibits higher water use, starting at ~7,500 AF currently and increasing to 10,000+ AF after 2040. All of the water is groundwater, very little of which is consumed and most of which is discharged to streams.

The scenario we favor is one in which potential increase in energy needs will be covered by western coal (which has been competing with local coal for decades, Figure 123), by other fossil fuels (gas?), or by a different energy source (nuclear?), but not by a massive extension of mouth-of-mine coal-fired power plants and concomitant increase in water use. In any case, a return to underground mining of subbituminous reserves is deemed unlikely.

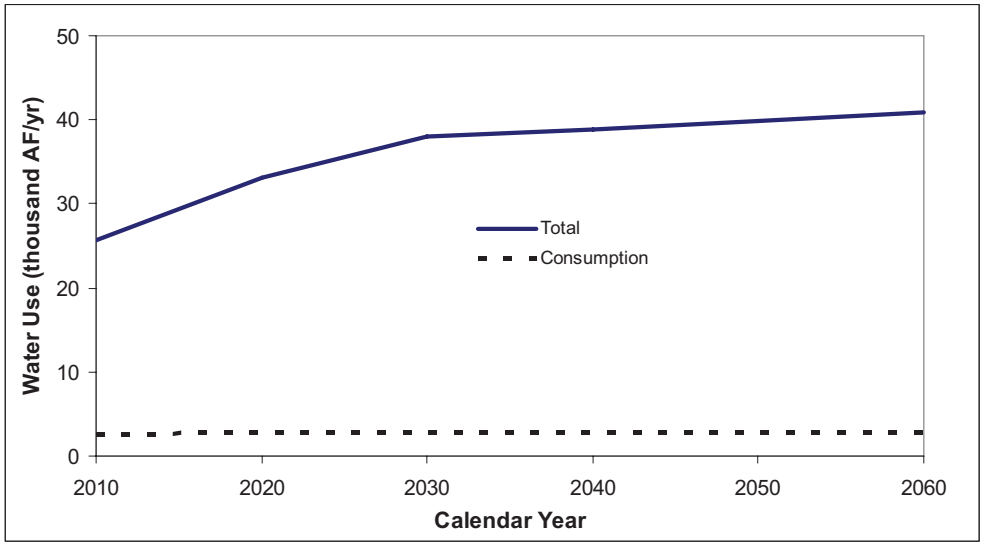
Table 60. Projected lignite-mine water use per county in AF/yr (2010–2060)

		TOTAL PUMPAGE						TOTAL CONSUMPTION					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,129	3,833	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	5,800	6,380	6,380	6,380	6,380	6,380	6	6	6	6	6	6
Monticello Thermo	Hopkins	920	900	900	900	900	900	205	201	201	201	201	201
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	667	833	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	694	4,333	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	982	982	1,500	1,500	1,500	1,500	855	855	855	855	855	855
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	1,265	1,668	1,668	1,668	1,668	1,668	582	582	582	582	582	582
Monticello Winfield	Titus	619	1,000	1,000	1,000	1,000	1,000	619	619	619	619	619	619
TOTAL		**25,689**	**33,110**	**37,946**	**38,845**	**39,835**	**40,924**	**2,562**	**2,650**	**2,668**	**2,677**	**2,687**	**2,668**
		PUMPAGE GROUNDWATER						**CONSUMPTION GROUNDWATER**					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,129	3,833	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	6	6	6	6	6	6	6	6	6	6	6	6
Monticello Thermo	Hopkins	735	719	719	719	719	719	21	20	20	20	20	20
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	667	833	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	694	4,333	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	554	554	1,072	1,072	1,072	1,072	428	428	428	428	428	428
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	741	1,144	1,144	1,144	1,144	1,144	58	58	58	58	58	58
Monticello Winfield	Titus	310	691	691	691	691	691	310	310	310	310	310	310
TOTAL		**18,449**	**25,294**	**30,130**	**31,030**	**32,020**	**33,109**	**1,116**	**1,209**	**1,227**	**1,236**	**1,246**	**1,227**

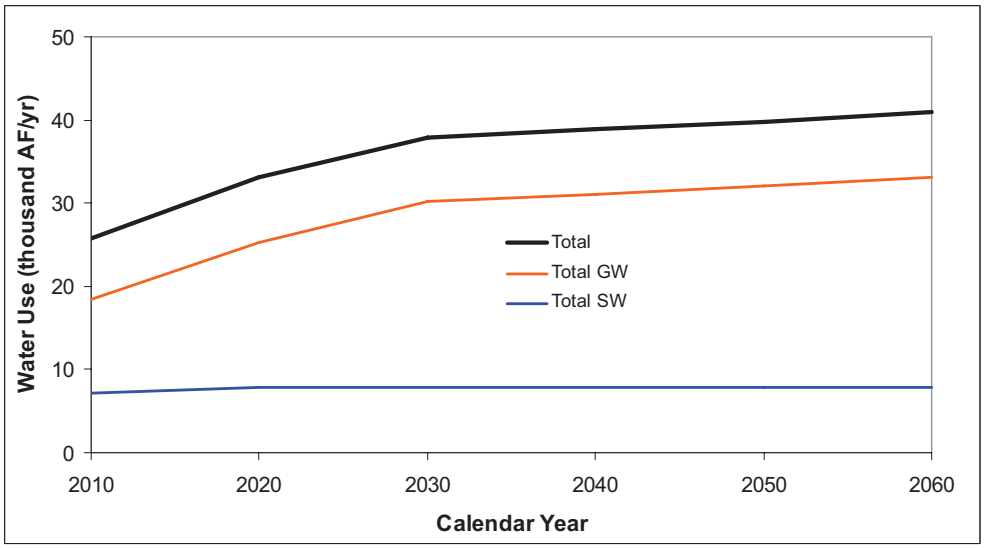
County+Pop_1-to-All(from Katy)_5.27.10_JP.xls

Table 60. Projected lignite-mine water use per county in AF/yr (2010–2060) (continued)

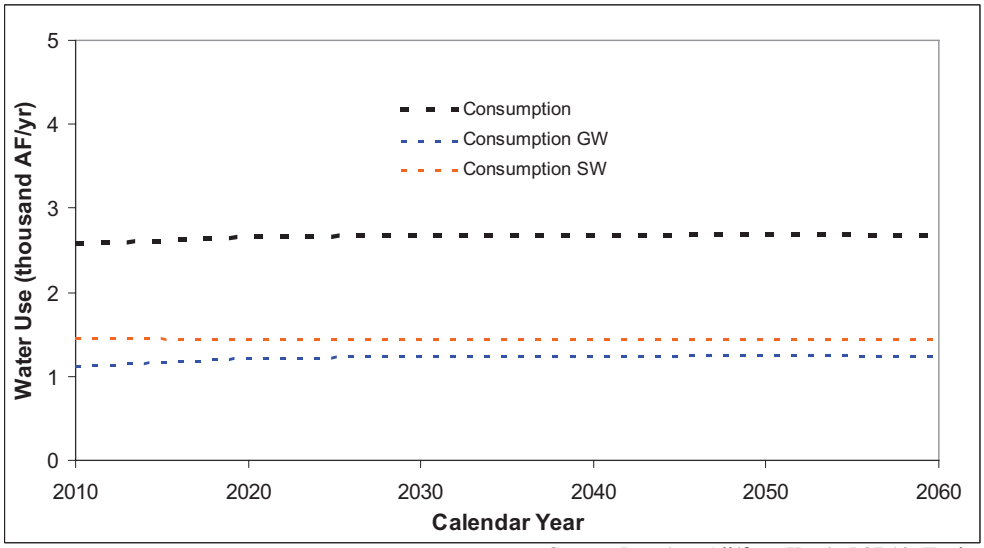
		PUMPAGE SURFACE WATER						CONSUMPTION SURFACE WATER					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	0	0	0	0	0	0	0	0	0	0	0	0
Big Brown, ⅓Jewett	Freestone	0	0	0	0	0	0	0	0	0	0	0	0
South Hallsville	Harrison	5,794	6,374	6,374	6,374	6,374	6,374	0	0	0	0	0	0
Monticello Thermo	Hopkins	185	181	181	181	181	181	185	181	181	181	181	181
½Three oaks	Lee	0	0	0	0	0	0	0	0	0	0	0	0
⅓Jewett	Leon	0	0	0	0	0	0	0	0	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	0	0	0	0	0	0	0	0	0	0	0	0
Martin Lake	Panola	428	428	428	428	428	428	428	428	428	428	428	428
Calvert, Twin Oak	Robertson	0	0	0	0	0	0	0	0	0	0	0	0
Oak Hill	Rusk	524	524	524	524	524	524	524	524	524	524	524	524
Monticello Winfield	Titus	310	310	310	310	310	310	310	310	310	310	310	310
TOTAL		**7,240**	**7,815**	**7,815**	**7,815**	**7,815**	**7,815**	**1,446**	**1,442**	**1,442**	**1,442**	**1,442**	**1,442**
		PUMPAGE FRESH WATER						**CONSUMPTION FRESH WATER**					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,095	3,792	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	5,800	6,380	6,380	6,380	6,380	6,380	6	6	6	6	6	6
Monticello Thermo	Hopkins	920	900	900	900	900	900	205	201	201	201	201	201
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	633	792	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	661	4,292	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	982	982	1,500	1,500	1,500	1,500	855	855	855	855	855	855
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	1,265	1,668	1,668	1,668	1,668	1,668	582	582	582	582	582	582
Monticello Winfield	Titus	619	1,000	1,000	1,000	1,000	1,000	619	619	619	619	619	619
TOTAL		**25,589**	**32,985**	**37,946**	**38,845**	**39,835**	**40,924**	**2,562**	**2,650**	**2,668**	**2,677**	**2,687**	**2,668**



(a)



(b)



(c)

County+Pop_1-to-All(from Katy)_5.27.10_JP.xls

Figure 121. Projected lignite-mine water use (2010–2060)

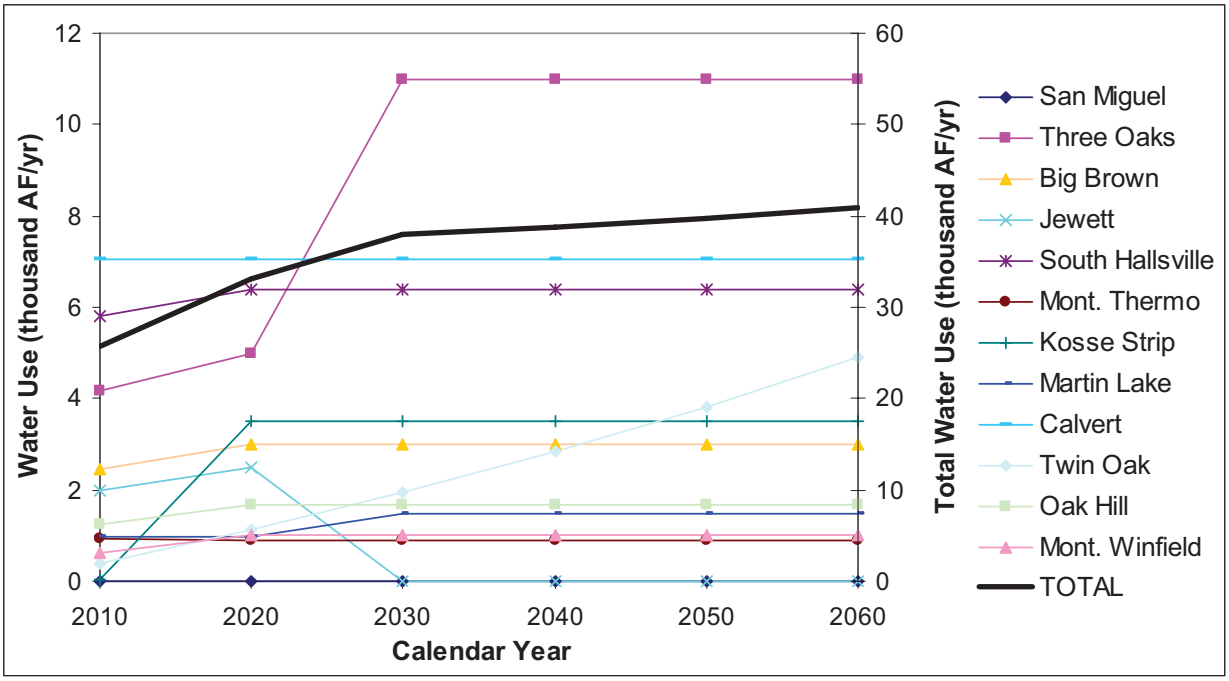


Figure 122. Total water use for each coal-mining facility

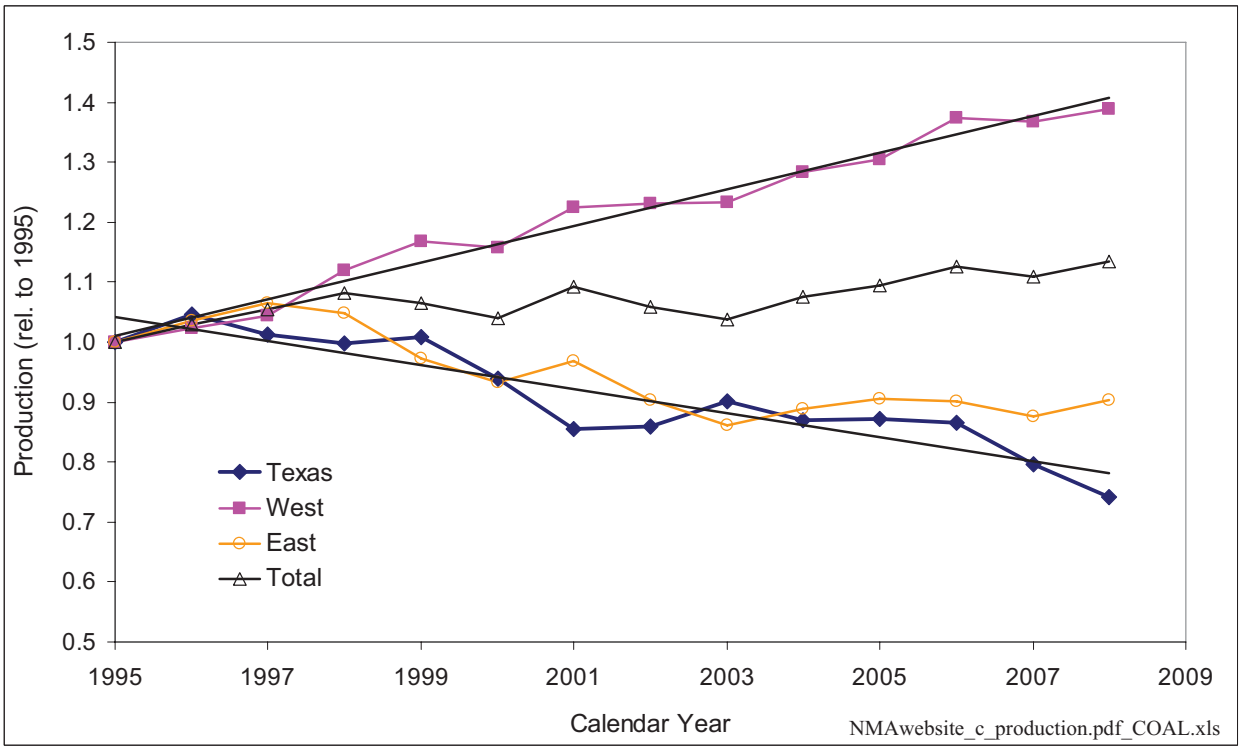


Figure 123. Relative growth of Texas (negative) and western (positive) coal

5.4 Aggregates

Key parameters for future aggregate water use relating population and aggregate production are presented in Table 61, Figure 124, and Figure 125. We assumed that crushed stone and construction sand and gravel will follow a trajectory similar to that of the past 2 decades. The production trajectory considered deviates from strict linear extrapolation of historical data and is somewhat flattened. The increased gap between crushed-stone and sand and gravel operations (Figure 125) is consistent with the societal trend of having large operations at one location for a long period of time, rather than having dispersed generally smaller sand and gravel operations. However, both categories are expected to grow in the future. The overall growth rate is 1.5%–2% (Table 61). Some analysts have projected an annual growth in the industry of 3%–5% (Walden and Baier, 2010). Although industry has been significantly impacted by the current economic recession, it is anticipated that demand for aggregate products will continue to grow with the population and the need for roadway and other building materials. It is not clear, however, how a 3% annual growth (translating into a production of ~1,200 million tons/yr in 2060) can be sustained in terms of water use without increasing water recycling or developing dry processes. The aggregate water use projections presented in this report can therefore be construed as either modest annual growth with no change from current practices or higher annual growth with concomitant decrease in water use. In addition, although most mining facilities are operated for at least 20 years, and although some larger operations have 100 years or more of reserves, small "mom & pop" quarries may be operated for as little as 5 years and are often associated with specific development projects or other short-term, localized demands. This observation carries the understanding that many small facilities could appear in counties not listed in Table 63, which shows sand and gravel water-use projections. Table 62 does the same for crushed stone. Table 64 summarizes projections displayed at the county level in Figure 126 and Figure 127. Overall aggregate will increase from ~50 thousand AF/yr in 2010 to ~100 thousand AF/yr in 2060.

Table 61. Historical and projected population and aggregate production

Year	Crushed Stone (million tons)	Sand and Gravel (million tons)	Population	Average Annual Population Change
1990	55	42	16,986,510	
2000	110	74	20,851,820	386,531
2010	164	105	25,388,403	453,658
2020	198	124	29,650,388	426,199
2030	232	144	33,712,020	406,163
2040	268	165	37,734,422	402,240
2050	307	187	41,924,167	418,975
2060	346	210	46,323,725	439,956

Table 62. Crushed-stone water use projections per county through 2060

County	2008	2010	2020	2030	2040	2050	2060
Bell	0.747	0.803	1.039	1.278	1.460	1.681	1.914
Bexar	3.108	3.341	4.051	4.603	5.038	5.502	6.070
Brown	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Burnet	0.280	0.301	0.384	0.460	0.535	0.598	0.678
Callahan	0.131	0.140	0.141	0.141	0.136	0.133	0.129
Comal	3.634	3.907	4.739	5.473	6.123	6.651	7.378
Cooke	0.818	0.880	1.133	1.349	1.576	1.893	2.181
Coryell	0.275	0.296	0.355	0.397	0.429	0.463	0.505
Eastland	0.150	0.161	0.168	0.178	0.211	0.213	0.225
Ector	0.168	0.181	0.196	0.212	0.218	0.229	0.240
Ellis	2.898	3.115	3.564	4.213	5.047	6.004	6.827
Floyd	0.169	0.182	0.190	0.195	0.202	0.208	0.213
Glasscock	0.095	0.102	0.107	0.112	0.114	0.117	0.121
Hidalgo	0.170	0.183	0.244	0.310	0.364	0.415	0.477
Hutchinson	0.127	0.137	0.152	0.172	0.186	0.193	0.207
Jack	0.238	0.256	0.302	0.322	0.363	0.405	0.450
Johnson	3.091	3.323	3.816	4.479	5.347	6.337	7.197
Kaufman	2.063	2.218	2.492	2.903	3.507	4.263	4.864
Lampasas	0.293	0.314	0.374	0.417	0.449	0.483	0.526
Limestone	0.210	0.226	0.250	0.280	0.294	0.332	0.359
Maverick	0.052	0.056	0.065	0.072	0.077	0.079	0.085
Medina	0.287	0.308	0.360	0.397	0.425	0.453	0.491
Montague	0.104	0.111	0.129	0.150	0.181	0.205	0.232
Nolan	0.023	0.025	0.025	0.025	0.024	0.023	0.022
Oldham	0.165	0.177	0.204	0.244	0.275	0.288	0.315
Parker	0.170	0.183	0.218	0.264	0.318	0.372	0.425
Potter	0.192	0.206	0.235	0.275	0.305	0.318	0.345
Reeves	0.014	0.015	0.016	0.016	0.017	0.018	0.019

County	2008	2010	2020	2030	2040	2050	2060
Sabine	0.053	0.057	0.060	0.063	0.066	0.069	0.072
San Patricio	0.340	0.366	0.419	0.464	0.491	0.510	0.546
Stonewall	0.019	0.021	0.020	0.019	0.019	0.018	0.017
Taylor	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Travis	0.135	0.145	0.188	0.230	0.272	0.310	0.355
Uvalde	0.055	0.059	0.072	0.078	0.081	0.086	0.093
Walker	0.454	0.488	0.660	0.842	1.086	1.337	1.572
Webb	0.226	0.243	0.331	0.435	0.521	0.611	0.710
Williamson	2.273	2.444	3.152	3.796	4.412	5.046	5.750
Wise	1.422	1.529	1.882	2.263	2.685	3.177	3.639
Young	0.035	0.038	0.040	0.043	0.045	0.049	0.052

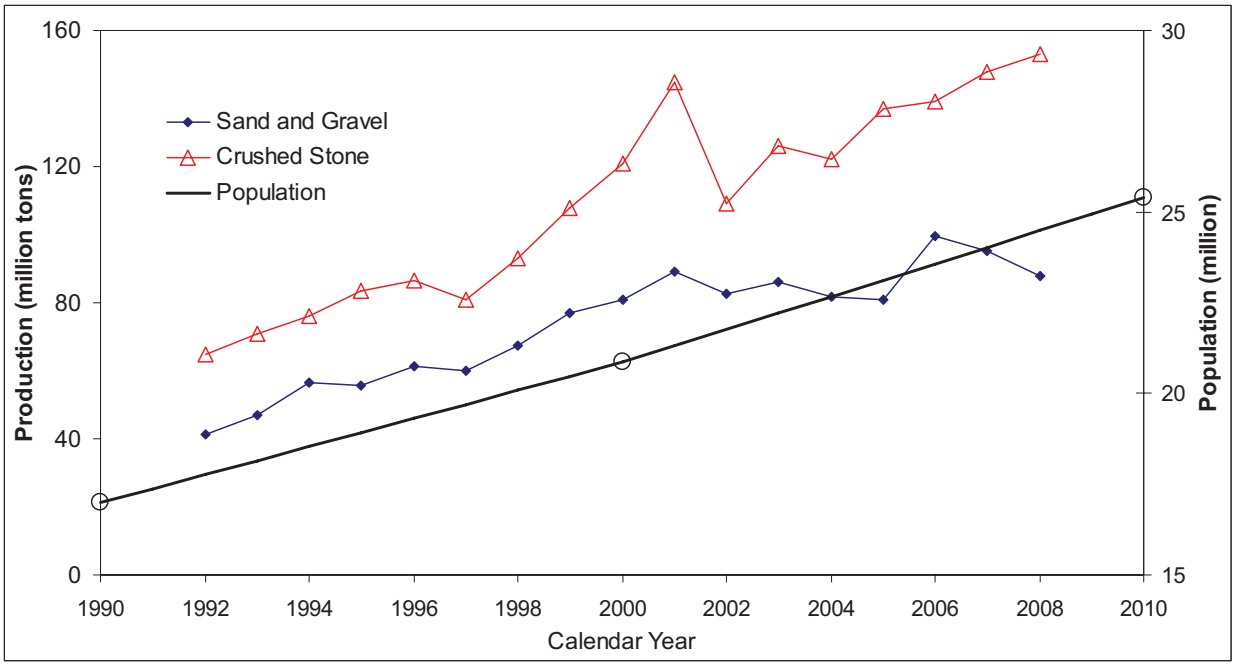
Table 63. Sand and gravel water-use projections per county through 2060

County	2008	2010	2020	2030	2040	2050	2060
Atascosa	0.350	0.420	0.526	0.615	0.698	0.755	0.846
Bastrop	0.063	0.076	0.113	0.162	0.225	0.310	0.387
Bell	0.346	0.415	0.523	0.622	0.710	0.800	0.907
Bexar	1.028	1.233	1.233	1.233	1.233	1.233	1.233
Borden	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Bosque	0.013	0.015	0.018	0.018	0.019	0.021	0.023
Brazoria	0.565	0.678	0.866	1.064	1.289	1.533	1.790
Brazos	0.230	0.276	0.347	0.403	0.495	0.474	0.521
Burnet	0.031	0.037	0.050	0.064	0.079	0.100	0.120
Coke	0.003	0.004	0.004	0.005	0.005	0.006	0.006
Colorado	1.540	1.848	2.033	2.190	2.372	2.440	2.543
Comal	0.099	0.119	0.180	0.242	0.305	0.382	0.464
Cooke	0.026	0.031	0.040	0.048	0.066	0.073	0.085
Dallas	1.574	1.889	1.889	1.889	1.889	1.889	1.889
Denton	1.262	1.514	2.106	2.678	3.332	4.293	5.191
Duval	0.604	0.725	0.796	0.846	0.810	0.748	0.713
El Paso	0.581	0.697	0.880	1.063	1.266	1.482	1.721
Fannin	0.006	0.007	0.011	0.016	0.023	0.027	0.033
Fayette	0.082	0.098	0.123	0.145	0.183	0.241	0.287
Fort Bend	0.000	0.000	0.000	0.000	0.001	0.001	0.001
Galveston	0.282	0.339	0.375	0.402	0.444	0.480	0.514
Grayson	0.041	0.049	0.061	0.073	0.089	0.106	0.125
Guadalupe	0.186	0.224	0.318	0.422	0.541	0.674	0.816
Harris	2.494	2.993	2.993	2.993	2.993	2.993	2.993
Henderson	0.115	0.138	0.181	0.235	0.304	0.395	0.477
Hidalgo	0.603	0.723	1.045	1.444	1.850	2.272	2.750
Hutchinson	0.023	0.027	0.028	0.027	0.026	0.027	0.026

County	2008	2010	2020	2030	2040	2050	2060
Jefferson	0.131	0.157	0.180	0.202	0.230	0.280	0.315
Johnson	0.075	0.090	0.121	0.162	0.214	0.281	0.342
Jones	0.010	0.012	0.013	0.013	0.013	0.013	0.013
Kaufman	0.195	0.234	0.296	0.386	0.491	0.646	0.783
Kerr	0.059	0.071	0.076	0.080	0.100	0.102	0.111
Lampasas	0.012	0.015	0.017	0.019	0.021	0.023	0.025
Liberty	0.108	0.129	0.165	0.206	0.253	0.310	0.365
Lubbock	0.415	0.498	0.554	0.601	0.676	0.745	0.807
McLennan	1.025	1.230	1.444	1.732	1.868	2.228	2.509
Medina	0.063	0.076	0.097	0.117	0.138	0.157	0.180
Montague	0.010	0.012	0.013	0.014	0.015	0.017	0.018
Montgomery	0.028	0.033	0.050	0.071	0.101	0.135	0.167
Navarro	0.062	0.075	0.096	0.123	0.155	0.198	0.236
Nueces	0.445	0.534	0.654	0.780	0.892	0.981	1.104
Oldham	0.002	0.002	0.002	0.001	0.001	0.000	0.000
Orange	0.136	0.163	0.176	0.191	0.220	0.238	0.256
Parker	0.253	0.304	0.393	0.424	0.503	0.580	0.674
Potter	0.308	0.370	0.456	0.583	0.711	0.790	0.909
Reeves	0.008	0.010	0.011	0.013	0.015	0.016	0.018
San Patricio	0.055	0.067	0.086	0.107	0.125	0.144	0.166
Smith	0.106	0.127	0.154	0.184	0.246	0.317	0.376
Somervell	0.386	0.463	0.552	0.613	0.636	0.668	0.715
Starr	0.142	0.170	0.229	0.296	0.357	0.418	0.491
Tarrant	1.093	1.312	1.312	1.312	1.312	1.312	1.312
Travis	0.718	0.862	0.862	0.862	0.862	0.862	0.862
Val Verde	0.031	0.037	0.046	0.054	0.060	0.065	0.072
Victoria	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ward	0.016	0.020	0.022	0.023	0.025	0.028	0.029
Washington	0.018	0.022	0.024	0.026	0.030	0.032	0.035
Webb	0.005	0.006	0.009	0.012	0.016	0.020	0.024
Wise	0.229	0.275	0.345	0.445	0.584	0.734	0.886

Table 64. Summary of aggregate water-use projections

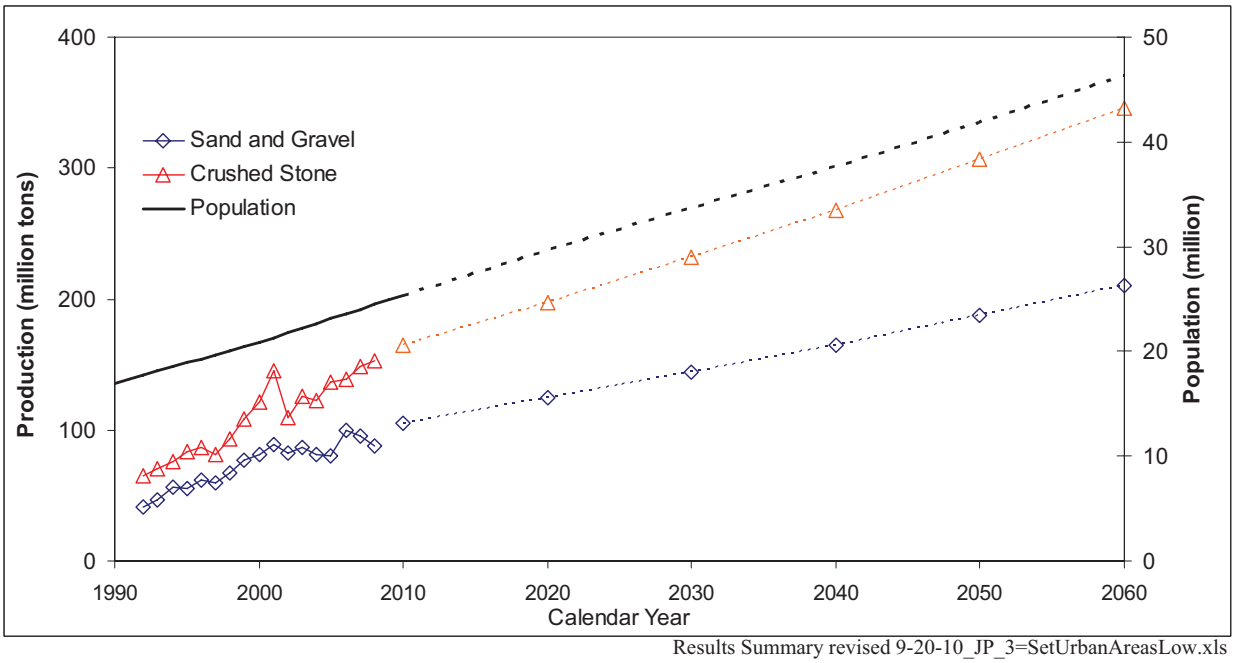
	2010	2020	2030	2040	2050	2060
Water-Use Projection (1000s AF)						
Crushed Stone	26.5	31.8	37.2	42.9	49.1	55.3
Sand and Gravel	22.0	25.2	28.6	32.1	36.1	40.3
Total	48.5	57.0	65.7	75.0	85.2	95.6



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Source: USGS (Aggregate production) and TWDB (population)

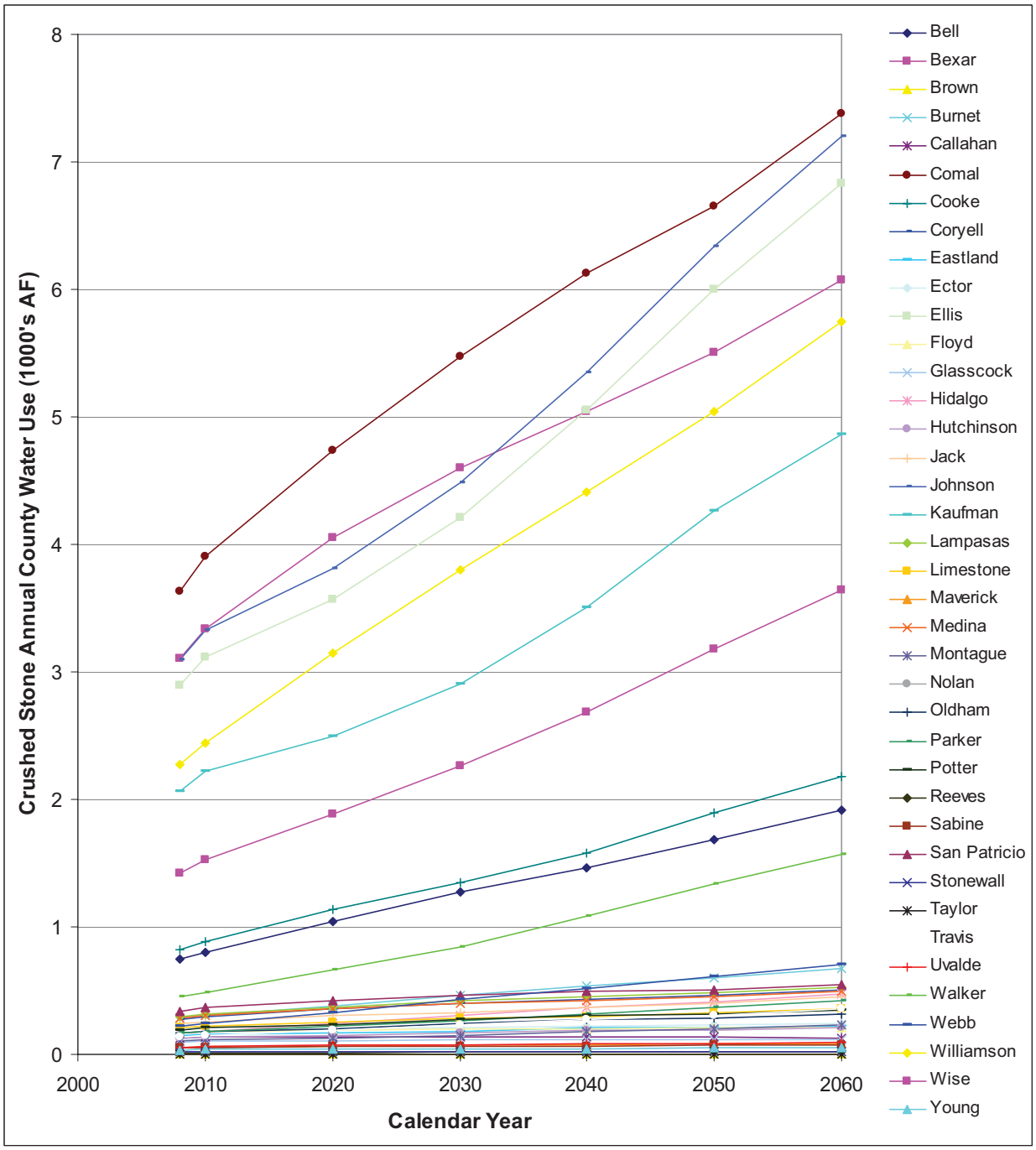
Figure 124. Historical population and aggregate production in Texas



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

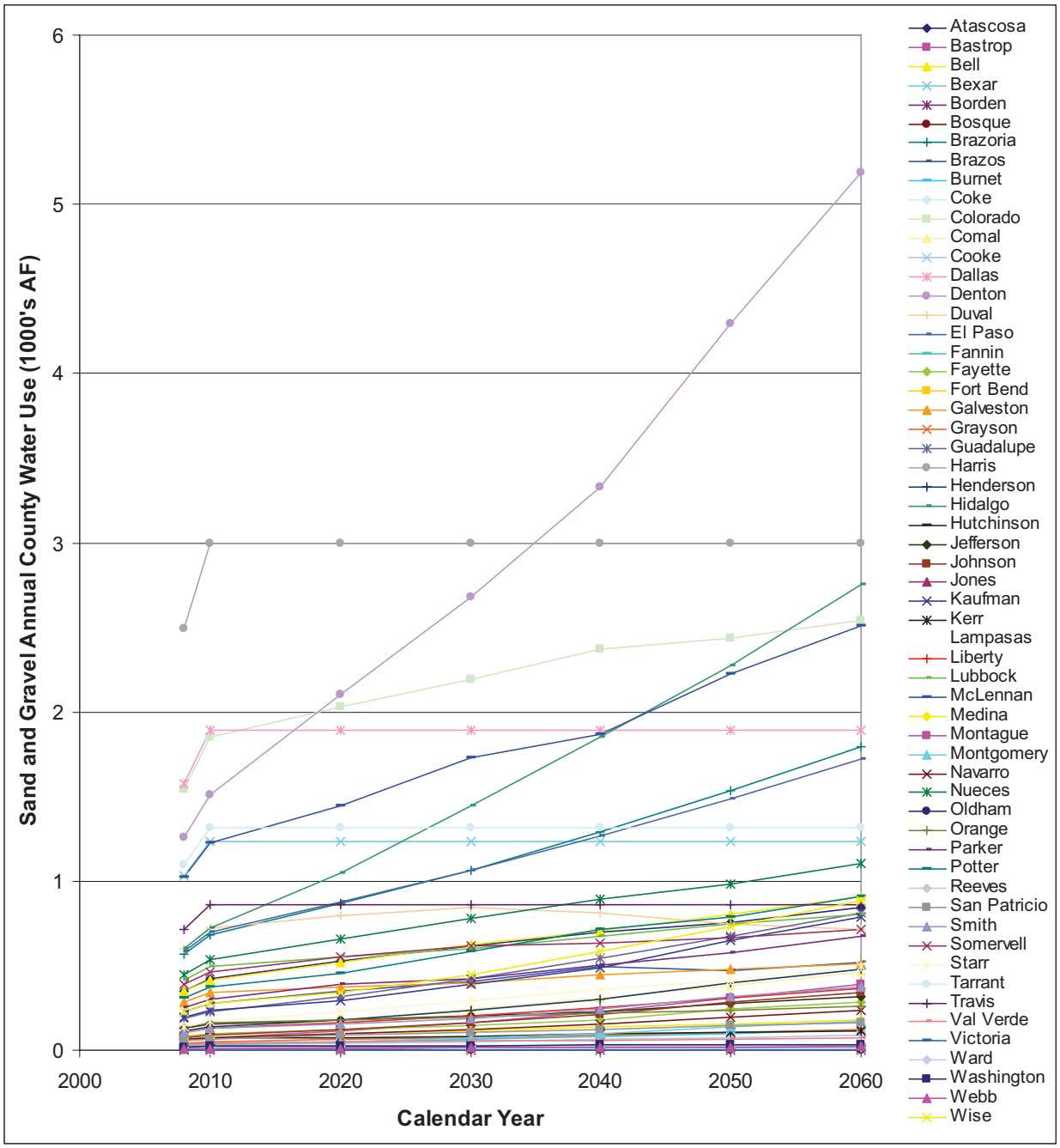
Source: USGS (aggregate production to 2008) and TWDB (population through 2060)

Figure 125. Historical population and projection for population and aggregate production in Texas



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Figure 126. Crushed-stone water-use projections per county through 2060



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Figure 127. Sand and gravel water-use projections per county through 2060

5.5 Industrial Sand

As seen in the Current Water Use section, industrial-sand mining is more water intensive than the closely related category of aggregate and consumes almost 10 thousand AF. Industrial-sand production is clearly connected to the increase in well stimulation/fracing through the use of proppants, although proppant sand used in Texas can be imported from out of state and sand produced in Texas exported out of state. There is no doubt that a significant fraction of the locally produced sand is used by the oil and gas industry. Assuming that a proppant loading of 1 lb/gal translates into 0.163 million tons/ thousand AF of frac water, then 35.8 thousand AF (2008 fracing water use) would correspond to 5.8 million tons. This figure is above the current Texas production of 3.58 million short tons in 2008 (Figure 128), suggesting that a significant fraction of the proppant is either not necessarily all natural sand or that it comes from out of state. A close examination of the production plot shows that departure from the background trend can be attributed to use to the oil and gas industry and that 1.5 million tons of industrial sand (only a fraction of the amount needed) was used, along with 38.5 thousand AF, to frac wells in Texas. We then assumed that this proportion stays constant in the next few decades (that is, that local production and imports from out of state grow at the same rate) and applied it to the water-use projections for fracing. We then distributed the results as they were distributed between counties and facilities in the Current Water Use section without incorporating important elements such as mining reserves or proximity to oil and gas plays. We assumed that the water coefficient would linearly improve from the current 620 gal/t to a value of 350 gal/t in 2060. The maximum water use close to 18 thousand AF is projected to be reached in the 2020–2030 decade (Table 65).

5.6 Other Nonfuel Minerals

In this section, we extrapolate from figures presented in the Current Water Use section. As we did previously, we neglect water use in the dimension-stone industry. We use extrapolation from current trends for lime and gypsum (Table 66 and Table 67) and expect no change in water use in clay, salt, sodium sulfate, or talc categories.

5.6.1 Uranium

The South Texas uranium province has already produced ~80 million lb U_3O_8. In 2003, EIA (2010) projected that 27 million lb U_3O_8 at 0.089% U_3O_8 on average and 40 million lb U_3O_8 at ~0.062% U_3O_8 on average remained in the ground in Texas, for a market price of $50 and $100/lb U_3O_8, respectively. As of January 2011, market price hovered at ~$60/lb. These reserves are, however, dwarfed by reserves in the western states (Wyoming, New Mexico, Arizona, Colorado, Utah), with 462 and 1,034 million lbs U_3O_8, for the same price cutoffs of $50 and $100/lb, respectively. In addition to the three counties with permits active in 2010 (Brooks, Duval, Kleberg), a sixth permit is pending at TCEQ in Goliad County; it has generated vigorous public participation. The RRC website lists exploration permits as of January 2011 in nine counties: Atascosa, Bee, Brooks, Duval, Goliad, Jim Hogg, Karnes, Kleberg, and Live Oak (and an additional permit in Briscoe County in the Texas Panhandle), to which can be added DeWitt, Jim Wells, McMullen, and Webb Counties (Figure 129). However, we assumed no change in current water use or of its distribution.

5.6.2 Other Metallic Minerals

On the basis of decades-long evaluation and development activities, three deposits seem to have potential for near-term mining: (1) Shafter silver deposit, Presidio County; (2) Round Top

beryllium-uranium-rare earth element deposit, Hudspeth County; and (3) Cave Peak molybdenum deposit, Culberson County.

5.6.2.1 Shafter Deposit

The Shafter deposit in Presidio County, 18 miles north of the Rio Grande, is the closest to actual production (http://www.aurcana.com/s/NewsReleases.asp?ReportID=439022), as plans for silver production by mid-2012 have been announced. This deposit is the downdip extension of the ore zone of the Presidio silver mine that was in production from 1883 until the early 1940s. The planned silver production follows a decade of activity by several predecessor companies, all building on an extensive exploration and limited development program in the late 1970s and early 1980s. The designed production rate for this underground mine is 1500 tons of ore per day, with measured and indicated reserves for more than 5 years of production, and additional resources for an additional 5 years of production, given favorable economic conditions. Burgess (2010) provided a detailed feasibility study for the Shafter mine, including plans for water management as: "*Two distinct phases in the water management plan are envisaged. The first phase will involve mining operations performed above the water table with no ground water being produced from this activity. During this phase, mining operations will be a small net consumer of water in the form of drill water and dust control water. Process plant make-up water will be obtained from the old underground workings in Block 1 which lie below the water table and are flooded with an estimated 20 million gallons of water. These old workings are recharged from a deep aquifer at a rate of 350 gpm, this figured being based on the inflows observed by Gold Fields when they were developing Block 1 in the early 1980´s. During this first phase of operations, no excess water will be generated as only the net requirements of the process plant and the underground workings will be drawn from the old workings of Block 1.*" and "*The second phase is when the decline face encounters the water table at approximately 900 Level, prior to which the 20 million gallons of water standing in the test mine in Block 1 will be pumped out through the Gold Fields shaft. By dewatering the Goldfields Shaft and Block 1 test mine in this manner, the water table will be lowered in advance of the decline face to reduce the amount of ground water encountered. The second phase also entails mining operations simultaneously occurring above the water table in Blocks 2 to 5. Mining Block 1 entails removing standing water (estimated at 20 million gallons) and groundwater inflows. This phase will produce a net excess of water of 350 gpm from ground water flowing into the underground mine which will be clarified in underground settling sumps to reach compliance with EPA criteria and then disposed of by discharge to the environment in a dry creek at the south west corner of the property (Arroyo del Muerto).*"

The Shafter ore zone is below the water table, so dewatering of the ore zone prior to and during production will more than account for any water used in mining per se. Furthermore, a considerable excess of water required for all of the Shafter operation will be produced. For the stated rate of ore production for the 5-year period, Burgess' s analysis indicates that total water used by the operation will average 104 AF per year, of which less than 20 AF per year will be used in mining and surface use around the mine. Source water derived from pumping of the ore zone will average 565 AF per year for the designed ore production rate of 1500 tons per day (even accounting for a nominal 10% ore dilution and development headings). Thus, **excess water production for the five-year period will average more than 500 AF per year (groundwater)**. If the current silver resources prove economically viable to extend production

beyond the initial five-year period, there is little reason to doubt that these relative figures would also apply to that extended amount and period of production.

5.6.2.2 Round Top Deposit

The Round Top beryllium-uranium-rare earth element deposit near Sierra Blanca in Hudspeth County is currently being reevaluated (http://www.standardsilvercorp.com/projects/round-top/), building on an extensive exploration program for beryllium in the 1980s (Rubin et al., 1990). The impetus for Round Top exploration has been boosted by the current emphasis on developing domestic REE sources to counter restricted supply from foreign sources, notably China. Although the mineralization controls at Round Top are only broadly understood, it is worth noting that this geologic environment is represented throughout a considerable portion of west Texas, suggesting regional potential for additional deposits. However, at this point, production even from the Round Top deposit would be hypothetical, and thus water needs are not possible to constrain.

5.6.2.3 Cave Peak Deposit

The molybdenum and associated metals deposit at Cave Peak in Culberson County has an exploration history also dating to the 1960s (Sharp, 1979). Following a considerable period of inactivity, the Cave Peak property has recently attracted renewed interest (http://www.quaterraresources.com/projects/cave_peak/). While geologically similar molybdenum deposits are sites of significant mining operations in other states, it is too early in the evaluation process to determine if Cave Peak represents an economically viable resource, let alone assess any potential water needs and impacts.

5.6.3 Conclusions

Uranium solution mining is likely to continue in Texas but a large increase in production and water use is not expected because of the competition of other deposits in the U.S. and elsewhere.

The planned Shafter mine has a life-expectancy in the decade range (currently 2012-2022), so barring discovery of substantial new resources locally, its water use (actually the mine's local supply of excess water) would not have a long term impact on regional water issues. Should any of the other metallic and industrial mineral deposits prove economically viable even at modest mining rates, even though the total water consumption likely would be relatively small, there could be significant impacts on local (ground)water supplies in the arid west Texas region.

Although Frasch sulfur is not produced anymore in Texas, sulfur remains a widely used industrial chemical, notably in the production of agricultural fertilizers, but the domestic and global sulfur supply currently is dominated by "nondiscretionary" sulfur recovery from refineries of sour crude oil and natural gas and from metal refineries as mandated by the Clean Air Act. Thus, it seems unlikely that Frasch sulfur production will ever return to economic viability in Texas, but should it do so, it could affect local water demand, particularly in west Texas. There are additional metal resources, namely zinc, lead, and silver, in association with some salt dome cap rocks that could represent a hypothetical mining activity over an extended timeframe (Kyle, 1999).

Table 65. Projected county-level industrial-sand water consumption

County	2008	2020	2030	2040	2050	2060
Atascosa	0.43	0.79	0.72	0.54	0.44	0.35
Colorado	0.43	0.79	0.72	0.54	0.44	0.35
Dallas	0.04	0.07	0.07	0.05	0.04	0.03
El Paso	0.04	0.07	0.07	0.05	0.04	0.03
Guadalupe	0.07	0.13	0.12	0.09	0.07	0.06
Harris	0.14	0.26	0.24	0.18	0.14	0.12
Hood	0.43	0.79	0.72	0.54	0.44	0.35
Hunt	0.07	0.13	0.12	0.09	0.07	0.06
Johnson	0.04	0.07	0.07	0.05	0.04	0.03
Liberty	0.14	0.26	0.24	0.18	0.14	0.12
Limestone	1.30	2.37	2.18	1.64	1.32	1.07
Mason	0.56	1.02	0.94	0.71	0.57	0.46
McCulloch	4.21	7.69	7.07	5.32	4.27	3.46
Montgomery	0.76	1.39	1.28	0.96	0.77	0.62
Newton	0.14	0.26	0.24	0.18	0.14	0.12
Orange	0.07	0.13	0.12	0.09	0.07	0.06
Robertson	0.04	0.07	0.07	0.05	0.04	0.03
San Saba	0.28	0.51	0.47	0.35	0.28	0.23
Smith	0.07	0.13	0.12	0.09	0.07	0.06
Somervell	0.14	0.26	0.24	0.18	0.14	0.12
Tarrant	0.21	0.38	0.35	0.27	0.21	0.17
Wise	0.07	0.13	0.12	0.09	0.07	0.06
Total	**9.68**	**17.68**	**16.26**	**12.24**	**9.82**	**7.95**

Table 66. Projected county-level lime-mining water consumption (AF)

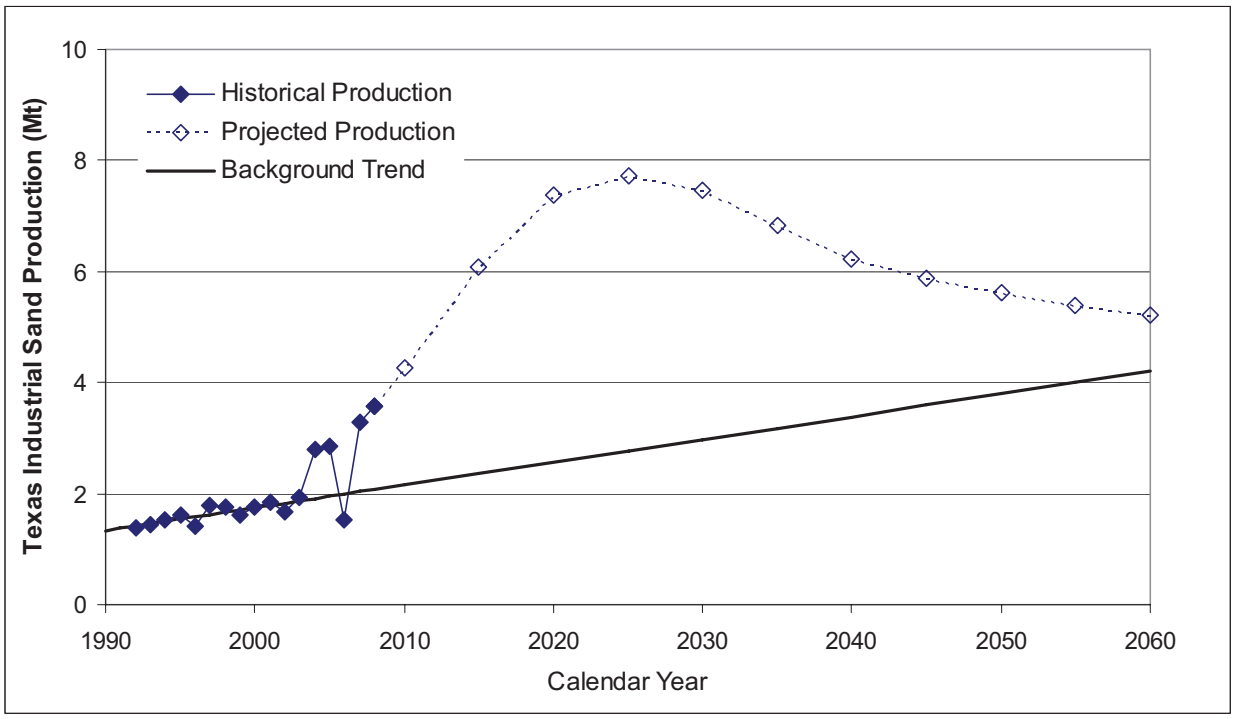
	2008	2020	2030	2040	2050	2060
Bosque	8.5	11.3	12.7	14.1	15.4	16.8
Burnet	2.8	3.7	4.1	4.5	5.0	5.4
Comal	6.6	8.7	9.8	10.8	11.9	12.9
Johnson	13.1	17.4	19.5	21.7	23.8	25.9
Travis	15.1	20.0	22.5	24.9	27.3	29.8
(AF)	**46**	**61**	**69**	**76**	**83**	**91**

Lime_count.xls

Table 67. Projected county-level gypsum-mining water consumption (AF)

	2008	2020	2030	2040	2050	2060
Fisher	3.3	4.0	4.0	4.0	4.0	4.0
Gillespie	3.3	4.0	4.0	4.0	4.0	4.0
Hardeman	6.6	8.0	8.0	8.0	8.0	8.0
Kimble	1.5	1.8	1.8	1.8	1.8	1.8
Nolan	14.8	17.8	17.8	17.8	17.8	17.8
Stonewall	1.2	1.4	1.4	1.4	1.4	1.4
Wheeler	1.2	1.4	1.4	1.4	1.4	1.4
(AF)	**32**	**38**	**38**	**38**	**38**	**38**

Gypsum_count.xls



IndustrialSand_count.xls

Figure 128. Projection of industrial-sand production

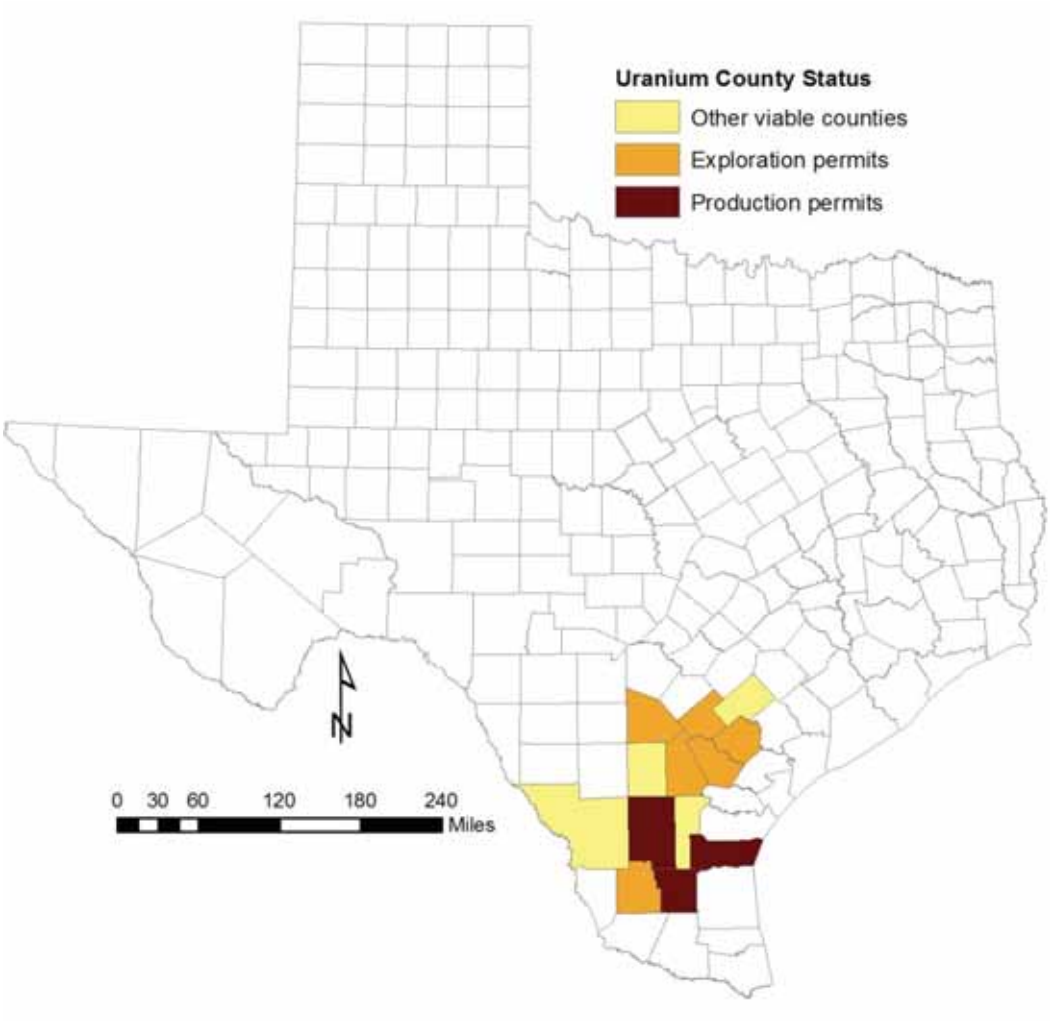


Figure 129. Counties prospective for uranium mining as of 2010

5.7 Water Use for Speculative Resources

Given that these resources are fairly speculative at this point and that even order-of-magnitude projections are impossible, their water use was not included in the projections. Information is provided, however, to alert stakeholders that it may be an option in the future when market conditions are favorable.

5.7.1 Heavy Oil

Large resources exist across the country and North America (for example, Veil and Puder, 2006; Veil and Quinn, 2008). Texas contains perhaps the largest heavy oil/tar sands reserves in the U.S after Utah. Heavy oil is generally defined as having an API density of between 10º and 20º. Below 10º API, the term *tar* (or *bitumen*) is generally used. Tar sands (called *oil sands* in Canada) of interest are San Miguel D and Anacacho of Cretaceous age in mostly Kinney, Maverick, Medina, Ulvalde, and Zavala Counties in the Maverick Basin. Asphaltic material (residue that occurs where a reservoir crops out after evaporation of the volatile or after water washing such as a reservoir subject to shallow groundwater systems) is still being produced in quarries operated by Vulcan Materials and by Martin-Marietta (Ewing, 2009, p. 27). Seni and Walter (1993) also mentioned heavy-oil deposits of Eocene age along the South Texas Gulf Coast (whether these accumulations have been or are currently produced through conventional means is unclear). Reserves of at least 3 Bbbl are reported (4.8 Bbbl in Kuuskraa et al., 1987), but they could be as high as 10 Bbbl (Ewing, 2009, p. 17). The *Oil&Gas Journal* (Moritis, 2010) claimed 7–10 Bbbl of OOIP. Heavy-oil deposits are different from oil shales, in which oil has not left the source rock and may still be in the form of kerogen, the chemical precursor to oil.

A typical production method consists of elevating the temperature of the deposits to lower the viscosity of the oil and allow it to flow to the production wells, which is done through steam injection or in situ combustion. Steam injection is used if the heavy oil is not too deep (<3,000 ft) because of heat loss along the well bores. Deposits, if shallow, can also simply be mined in open pits (as is done in Canada) and processed using steam. Stang and Soni (1984) mentioned a steam:oil ratio of 10.9 and 8.2 on two 1+-year-long test sites. U.S. DOE (ca. 2007) described the <3 ratio of Canada tar sands as being particularly favorable. Veil and Quinn (2008, p. 47) mentioned a ratio of 9 bbl/bbl for the Chevron operations in Kern River field in California, about half of the water being recycled. They also discussed other field-water use, ranging from 2 to 12 bbl/bbl. Figures in Torrey (1967, Table 6) projecting water use for the whole state of Texas suggest an average ratio of 3.9 bbl/bbl (for an oil production of ~2.7 Bbbl). The *Oil&Gas Journal* (Koottungal, 2010) reported that a steam flood is operating in Anderson County, although it is unclear what the target of the flood is. In a hypothetical case that 50% of the resource is recoverable (Tyler, 1984, p. 147; Stang and Soni, 1984), recovered solely through steam injection, and that it will be exhausted in 50 years, this scenario could be represented as 5×10^9 bbl /2 /50 yr × 5 bbl/bbl × 42 gal/bbl /325,851 gal/AF/1,000 = 32 thousand AF/yr, that is, 16 thousand AF/yr with a recycling of 50%. This amount does not include potentially needed dewatering of the shallow aquifers. Other much smaller deposits also exist across the state (Tyler, 1984), but their potential production contribution is dwarfed by the uncertainty of the South Texas deposits.

Cyclic interest (20–30 year cycle?) in these resources generally occurs when the price is oil is reasonably high—as it is currently (new tests were very recently performed) and as it was in the early 1980s. In the 1960s, although oil prices were stable, Texas underwent a steady growth in

field development as well, interrupted by the 1971 RRC decision to lift the production limit (Nicot, 2009b).

5.7.2 Enhanced Coalbed Methane Recovery

Coalbed methane (CBM) is generally produced by depressurization (that is, water production) of the formation that the coal seams are part of. A drop in pressure releases some of the methane sorbed to the coal matrix. PGC (2010, Table 91 and p. 359) mentioned a figure of 3.4 Tcf of gas in the speculative category (compared with 156.2 Tcf in the combined probable, possible, and speculative categories) for Texas and Louisiana Gulf Coast Pliocene-Eocene lignites. These figures are not entirely accurate at present because CBM is currently produced from Louisiana coal (Echols, 2001; Clayton and Warwick, 2006; Foss, 2009), although they do underline the small potential. Louisiana and East Texas Wilcox coal seams have a low dip, resulting in a large economical surface footprint whereas Central Texas Wilcox has a steeper dip resulting in a smaller potential for economic production (P. Warwick, USGS, personal communication, 2010); that is, coal plunges quickly beyond economical depth. The coal may have been charged through local bioprocesses (MacIntosh et al., 2010) or by thermogenic gas migrating from deeper in the basin (Arciniegas, 2006; McVay et al., 2007). How much of that water required being extracted would be fresh, brackish, or saline is unclear.

In addition, a company has apparently successfully tested the gas potential of Olmos coals in the Maverick Basin (San Filipo, 1999; PGC, 2010, p. 359). PGC (2010, p. 360) pointed out that, despite the presence of Pennsylvanian-Permian coal, the Fort Worth/Strawn Basins do not seem to contain potentially recoverable resources, in disagreement with an interpretation by Hackley et al. (2009b).

5.7.3 Coal to Liquid

The production of coal and, thus, water through dewatering, may also be affected by an increasing interest in coal-to-liquids (or coal liquefaction) technologies (CTL). CTL involves the conversion of solid coal through direct or indirect coal liquefaction into liquid fuels and chemicals by breaking down coal's molecular structure and adding hydrogen. Whereas no known pilot plants exist in Texas (one is planned in Natchez, Mississippi), future interest in the possibility of creating liquid fuel from lignite may increase coal production in the long term. Because lignite is cheap and abundant within Texas, its practical application is for mine-of-mouth operations. There are, therefore, no transportation costs, offsetting the cost of burning lower grade coal, a more dependable and local source of fuel. However, the need for liquid fuels to compete with oil and natural gas may increase the possibility that coal will be used for CTL production. A discussion of the implications, management strategies, and obstacles facing CTL production will provide insight into its application as a liquid fuel rather than a source of electricity.

Because the need for a nearby abundant water supply can be a problem for many CTL plants, it would be logical to mine lignite where depressurization is needed, that is, the Wilcox lignite of Central Texas. An estimate comes to ~5 to 8 bbl of water per barrel of CTL (this is, manufacturing water use) (Hebel, 2010, Chapter 3). An average of 1.5 to 1.8 bbl of CTL is produced per ton of coal. Full-scale CTL plants are expected to operate at 30,000 to 80,000 bpd. At the low end, a plant would consume ~6.5 million tons of coal per year (Hebel, 2010, Chapter 4), as well as 8.5 thousand AF/yr of water. The ability to use the water pumped from depressurization and dewatering needs of a coal mine would enhance the sustainability of a CTL

plant by not putting additional pressure on the groundwater resources. Also, it is likely that a CTL would need deep water wells as the nearby coal-mine operations draw down the aquifer, which increases the amount of energy needed to pump the water. Overall, start of coal-to-liquid operations will increase coal mining and water use in both manufacturing and mining sectors.

5.8 Conclusions and Synthesis for Future Water Use

Combining all water uses, projections suggest that peak mining-water use will occur in the 2020–2030 decade at ~250 thousand AF, sustained by oil and gas activities (Figure 130). Hydraulic fracturing represents the most significant fraction of oil and gas mining use (Figure 131). Percentages of oil and gas water use currently below 50% of total water use, would reach its largest fraction at 50+% in 2015–2030. Fracing is dominant in that use (Figure 132). Eventually oil and gas water use will be slowly taken over by aggregate-water use, which is projected to constitute >50% of total mining-water use by 2050 (Figure 133).

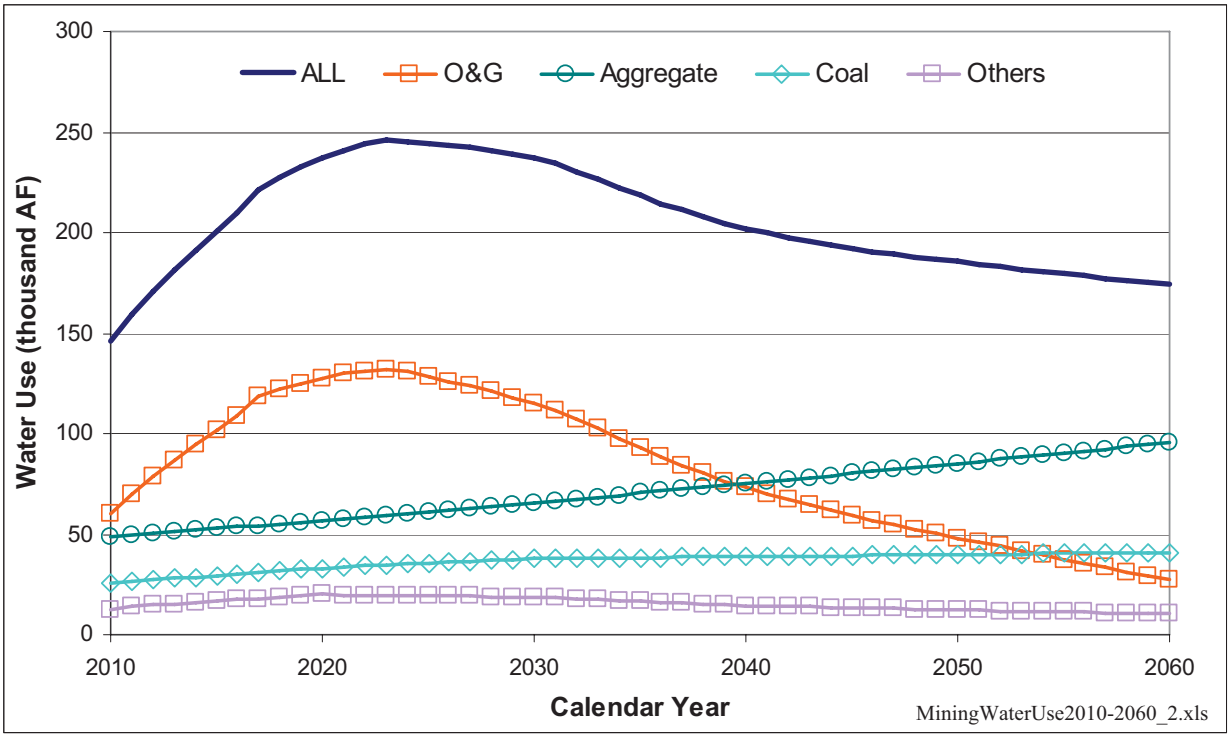


Figure 130. Summary of projected water use by mining-industry segment (2010–2060)

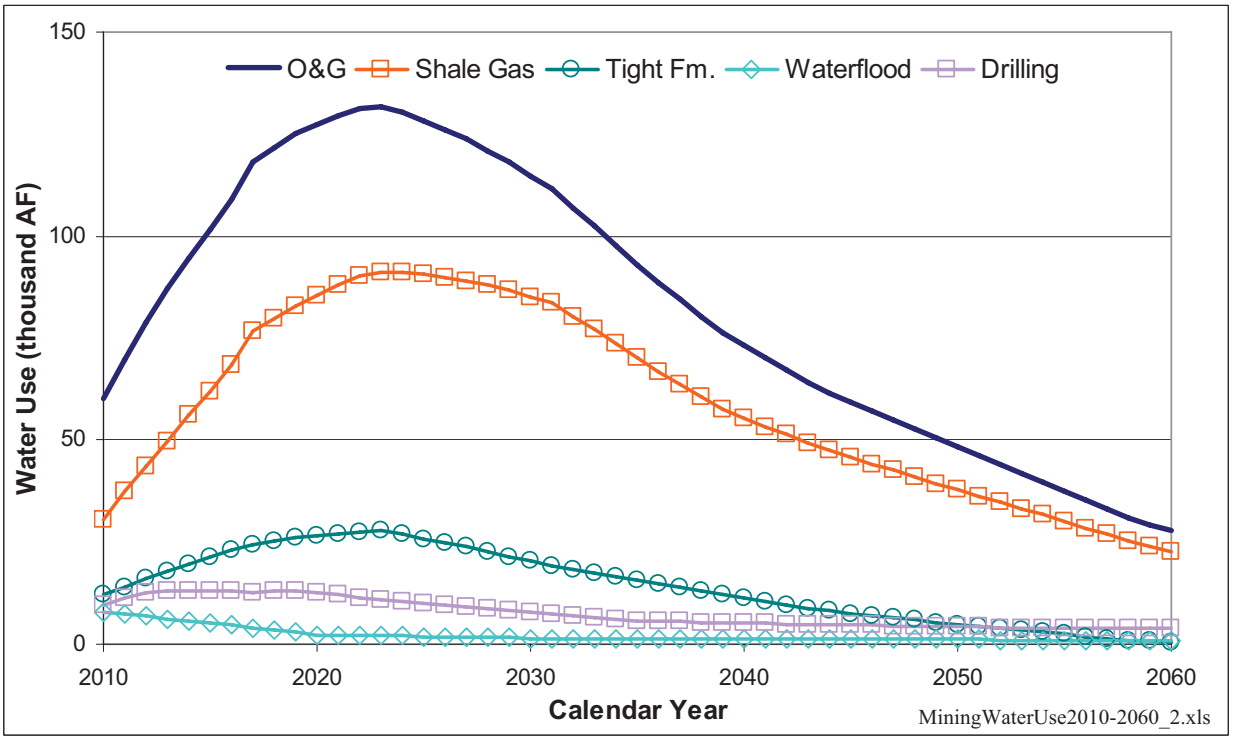


Figure 131. Summary of projected water use in the oil and gas segment (2010–2060)

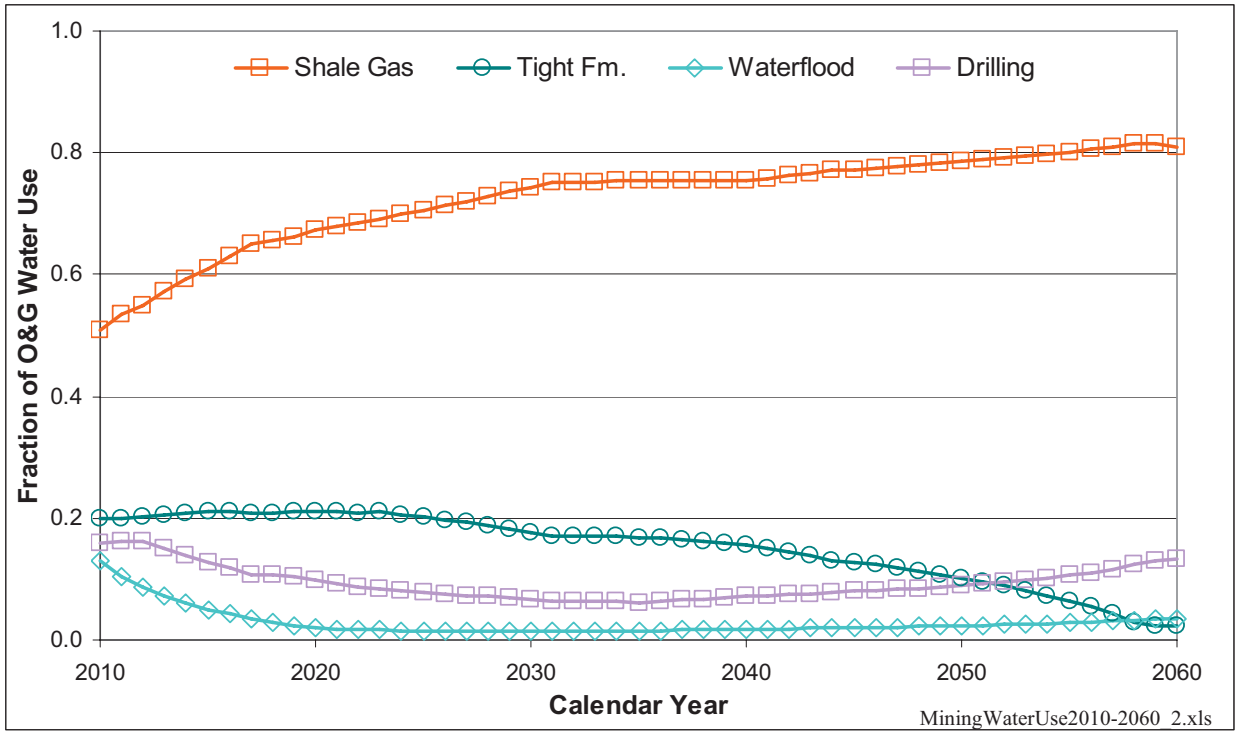


Figure 132. Summary of relative fraction of projected water in the oil and gas segment (2010–2060)

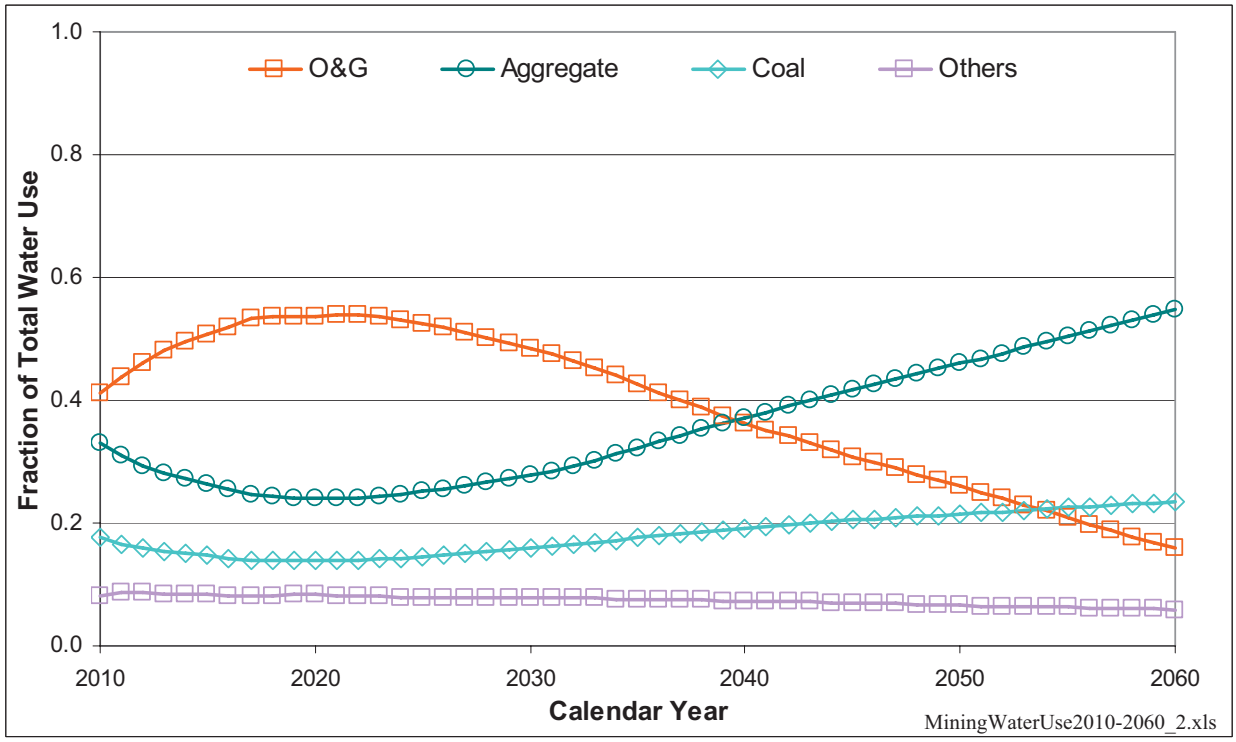


Figure 133. Summary of relative fraction of projected water use by mining-industry segment (2010–2060)

6 Conclusions and Recommendations

This study was undertaken to help in constraining water use in the mining industry. Overall in 2008, the industry as a whole consumed ~140 thousand AF of fresh water. The uncertainty associated with this value is relatively high as only figures from the coal industry (26.7 thousand AF) are well known because of legal requirements. Water usage for fracing in the oil and gas industry is also relatively well-constrained (35.8 thousand AF) because reported to the RRC with other parameters gathered during well completion. Other water uses in the oil and gas industry such as for drilling and waterfloods (21 thousand AF) are known by about a factor 2. Fresh water use for aggregate and similar commodities (lime, industrial sand, etc) production are not well-known and rely on educated guesses supported by limited survey results. We also estimate that fresh-water use is known by about a factor 2 for sand and gravel operations and maybe by a factor of 1.5 for generally larger crushed stone and industrial sand operations. Water use from some large facilities or some small contributors (uranium, metallic substances) are well documented but they make up only a small fraction of the total state water use. Applying those uncertainty factors implies that the true water use is within the 105-195 thousand AF range but those bounds are much less likely than the value of ~140 thousand AF derived in this document (Figure 134). Table 68 presents year 2008 overall water use results at the county leve. Clearly the uncertainty increases as the area of interest decreases in size, particularly if it contains unaccounted-for aggregate facilities or if the facility size has been overestimated. Comparison between published TWDB estimates and results of this work (Figure 135) shows that, by selecting the top 20 high water user counties in the mining category, only 10 of them overlapped.

County-level projections for the 2010-2060 period are given in Table 69. They suggest that peak mining-water use will occur in the 2020–2030 decade at ~250 thousand AF, decreasing to ~175 thousand AF by 2060. Many assumptions went into the building of the projections, in particular related to the activities of the oil and gas industry. Water use for those counties in which a large component of the mining water use is from shale gas fracing or those counties overlying currently little-known (mostly deep) oil or gas accumulations can deviate dramatically from the projections owing to political/legal and economic factors. Water use projections could be improved if the starting point, current water use, was better known.

This study emphasized the difficulties in gathering information on water use and the disappointing limitations of voluntary surveys, in particular whether the surveyed entities are representative of their respective mining segment as a whole. In other words, our survey sampling is likely biased. The low response rate may reflect the general reluctance of the mining industry to provide competitively sensitive information that is not required or to divert staff resources to obtain and submit data that is not routinely kept for business purposes.

Continuing to work with trade associations and expanding that cooperation to include other organizations appears to be necessary and appropriate to improve data collection. Lessons learned from this study can be used to develop refined, focused data collection, designed in consultation with a small workgroup of mining-industry representatives and related agencies and organizations, to effectively ground-truth water use/consumption and production assumptions in the industry and to calculate water-use coefficients on the basis of an acceptable, reproducible methodology. A useful alternative approach would be to make use of the recent progress in analyzing satellite imagery (in particular through time) to complement/confirm data obtained through surveys.

Table 68. County-level summary of mining water use (oil and gas drilling not included)

County	Mining Water Use (AF)	County	Mining Water Use (AF)	County	Mining Water Use (AF)
Anderson	13	Gillespie	3	Moore	1
Andrews	684	Glasscock	346	Morris	0
Angelina	90	Goliad	9	Motley	4
Aransas	0	Gonzales	0	Nacogdoches	384
Archer	7	Gray	24	Navarro	70
Armstrong	0	Grayson	43	Newton	141
Atascosa	781	Gregg	128	Nolan	112
Austin	0	Grimes	0	Nueces	453
Bailey	0	Guadalupe	256	Ochiltree	77
Bandera	0	Hale	109	Oldham	171
Bastrop	2,152	Hall	0	Orange	206
Baylor	0	Hamilton	0	Palo Pinto	235
Bee	6	Hansford	4	Panola	1,926
Bell	1,093	Hardeman	7	Parker	2,191
Bexar	4,136	Hardin	1	Parmer	0
Blanco	0	Harris	3,169	Pecos	238
Borden	126	Harrison	6,673	Polk	0
Bosque	21	Hartley	3	Potter	501
Bowie	0	Haskell	31	Presidio	0
Brazoria	568	Hays	0	Rains	0
Brazos	239	Hemphill	721	Randall	0
Brewster	0	Henderson	143	Reagan	460
Briscoe	0	Hidalgo	847	Real	2
Brooks	295	Hill	1,137	Red River	1
Brown	8	Hockley	1,881	Reeves	153
Burleson	34	Hood	2,584	Refugio	0
Burnet	314	Hopkins	935	Roberts	216
Caldwell	0	Houston	13	Robertson	7,684
Calhoun	3	Howard	56	Rockwall	0
Callahan	160	Hudspeth	0	Runnels	27
Cameron	0	Hunt	70	Rusk	1,836
Camp	4	Hutchinson	156	Sabine	53
Carson	1	Irion	105	San Augustine	88
Cass	0	Jack	323	San Jacinto	0
Castro	0	Jackson	4	San Patricio	398
Chambers	0	Jasper	0	San Saba	280
Cherokee	120	Jeff Davis	0	Schleicher	16
Childress	0	Jefferson	131	Scurry	39
Clay	22	Jim Hogg	2	Shackelford	75
Cochran	390	Jim Wells	0	Shelby	0
Coke	37	Johnson	11,678	Sherman	3
Coleman	35	Jones	51	Smith	235
Collin	0	Karnes	0	Somervell	697
Collingsworth	0	Kaufman	2,258	Starr	209

County	Mining Water Use (AF)	County	Mining Water Use (AF)	County	Mining Water Use (AF)
Colorado	1,972	Kendall	0	Stephens	1,786
Comal	3,740	Kenedy	27	Sterling	67
Comanche	1	Kent	297	Stonewall	238
Concho	27	Kerr	59	Sutton	1
Cooke	1,081	Kimble	1	Swisher	0
Coryell	275	King	121	Tarrant	6,450
Cottle	2	Kinney	0	Taylor	25
Crane	403	Kleberg	280	Terrell	12
Crockett	113	Knox	1	Terry	99
Crosby	20	Lamar	0	Throckmorton	69
Culberson	64	Lamb	13	Titus	622
Dallam	0	Lampasas	305	Tom Green	32
Dallas	1,690	La Salle	27	Travis	868
Dawson	250	Lavaca	18	Trinity	0
Deaf Smith	0	Lee	2,089	Tyler	0
Delta	0	Leon	740	Upshur	43
Denton	4,013	Liberty	248	Upton	1,313
DeWitt	13	Limestone	2,469	Uvalde	55
Dickens	9	Lipscomb	145	Val Verde	33
Dimmit	49	Live Oak	3	Van Zandt	492
Donley	0	Llano	0	Victoria	0
Duval	904	Loving	68	Walker	454
Eastland	277	Lubbock	774	Waller	0
Ector	509	Lynn	51	Ward	87
Edwards	2	McCulloch	4,220	Washington	18
Ellis	2,994	McLennan	1,025	Webb	349
El Paso	621	McMullen	44	Wharton	6
Erath	295	Madison	0	Wheeler	1,074
Falls	0	Marion	30	Wichita	20
Fannin	6	Martin	569	Wilbarger	3
Fayette	82	Mason	560	Willacy	5
Fisher	153	Matagorda	8	Williamson	2,273
Floyd	169	Maverick	75	Wilson	1
Foard	1	Medina	350	Winkler	30
Fort Bend	4	Menard	2	Wise	3,938
Franklin	2	Midland	700	Wood	6
Freestone	3,631	Milam	0	Yoakum	863
Frio	4	Mills	0	Young	38
Gaines	3,033	Mitchell	75	Zapata	107
Galveston	282	Montague	691	Zavala	0
Garza	196	Montgomery	788	**SUM**	**129,662***

*: oil and gas drilling not included

MiningWaterUse2010-2060_2.xls

Table 69. County-level summary of 2010-2020 projections for mining water use (oil and gas drilling not included)

County	2010	2020	2030	2040	2050	2060
Anderson	8	26	84	67	42	16
Andrews	678	1,014	743	377	152	47
Angelina	0	426	534	367	200	33
Aransas	9	17	22	16	11	5
Archer	3	1,619	1,293	370	0	0
Armstrong	0	0	0	0	0	0
Atascosa	851	2,998	4,368	3,672	3,055	2,497
Austin	0	48	256	279	221	163
Bailey	0	0	0	0	0	0
Bandera	0	0	0	0	0	0
Bastrop	2,164	2,613	5,662	5,725	5,810	5,887
Baylor	0	0	0	0	0	0
Bee	23	47	58	43	29	14
Bell	1,218	1,562	1,901	2,170	2,481	2,821
Bexar	4,574	5,284	5,836	6,271	6,736	7,304
Blanco	0	0	0	0	0	0
Borden	109	395	318	165	58	0
Bosque	937	2,576	1,096	33	37	40
Bowie	0	0	0	0	0	0
Brazoria	716	941	1,157	1,359	1,578	1,812
Brazos	276	865	1,534	1,418	1,187	1,024
Brewster	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0
Brooks	305	329	342	326	310	294
Brown	5	1	1	1	1	1
Burleson	0	594	1,295	1,055	816	576
Burnet	341	437	528	619	704	804
Caldwell	0	0	0	0	0	0
Calhoun	17	33	42	31	21	10
Callahan	158	146	145	139	135	131
Cameron	25	50	62	46	30	14
Camp	3	1	1	0	0	0
Carson	0	0	0	0	0	0
Cass	0	52	66	46	25	4
Castro	0	0	0	0	0	0
Chambers	0	0	0	0	0	0
Cherokee	23	254	288	188	89	0
Childress	0	0	0	0	0	0
Clay	635	3,731	1,664	0	0	0
Cochran	5	2	1	1	1	1
Coke	114	38	26	23	21	20
Coleman	21	6	4	3	3	3
Collin	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0

County	2010	2020	2030	2040	2050	2060
Colorado	2,304	3,728	4,851	4,490	4,087	3,744
Comal	4,033	4,928	5,725	6,438	7,044	7,855
Comanche	429	2,524	1,125	0	0	0
Concho	108	33	21	18	15	13
Cooke	1,016	1,457	1,516	1,643	1,966	2,267
Coryell	296	2,147	1,537	692	463	505
Cottle	7	2	1	1	1	1
Crane	144	297	225	99	43	31
Crockett	58	121	71	21	1	1
Crosby	228	69	43	37	32	28
Culberson	33	1,334	4,126	3,236	2,533	1,830
Dallam	0	0	0	0	0	0
Dallas	2,549	2,731	2,227	1,940	1,930	1,922
Dawson	147	404	324	170	63	5
Deaf Smith	0	0	0	0	0	0
Delta	0	0	0	0	0	0
Denton	3,188	2,693	2,678	3,332	4,293	5,191
DeWitt	24	1,114	1,740	1,402	1,063	725
Dickens	0	0	0	0	0	0
Dimmit	218	2,625	3,790	2,999	2,275	1,551
Donley	0	0	0	0	0	0
Duval	1,052	1,170	1,243	1,177	1,085	1,020
Eastland	231	1,317	1,348	608	223	234
Ector	499	762	630	413	290	243
Edwards	0	0	0	0	0	0
Ellis	3,440	3,799	4,276	5,047	6,004	6,827
El Paso	737	953	1,131	1,317	1,523	1,754
Erath	2,017	2,500	882	0	0	0
Falls	0	0	0	0	0	0
Fannin	7	11	16	23	27	33
Fayette	98	965	1,982	1,680	1,398	1,104
Fisher	94	32	21	19	17	15
Floyd	213	200	201	207	212	217
Foard	1	0	0	0	0	0
Fort Bend	23	47	58	44	29	14
Franklin	1	0	0	0	0	0
Freestone	3,766	4,862	4,268	3,984	3,493	3,026
Frio	0	180	744	717	566	414
Gaines	584	1,060	933	676	498	400
Galveston	339	375	402	444	480	514
Garza	77	155	91	27	2	1
Gillespie	3	4	4	4	4	4
Glasscock	492	1,414	1,230	740	364	131
Goliad	22	45	56	42	27	13
Gonzales	0	79	420	458	363	267
Gray	14	4	3	2	2	2
Grayson	50	62	73	89	107	125

County	2010	2020	2030	2040	2050	2060
Gregg	132	422	573	398	222	51
Grimes	0	59	314	342	271	200
Guadalupe	294	446	540	629	745	873
Hale	271	82	51	45	39	33
Hall	0	0	0	0	0	0
Hamilton	190	1,118	498	0	0	0
Hansford	75	675	62	0	0	0
Hardeman	7	8	8	8	8	8
Hardin	0	0	0	0	0	0
Harris	3,668	3,784	3,763	3,705	3,670	3,643
Harrison	7,044	9,418	8,624	7,850	7,076	6,380
Hartley	2	0	0	0	0	0
Haskell	19	6	4	3	3	2
Hays	0	0	0	0	0	0
Hemphill	694	364	33	0	0	0
Henderson	138	440	562	529	518	498
Hidalgo	948	1,372	1,858	2,292	2,738	3,251
Hill	1,008	1,249	441	0	0	0
Hockley	1	0	0	0	0	0
Hood	2,150	1,775	937	544	436	353
Hopkins	929	903	902	901	901	901
Houston	0	0	0	0	0	0
Howard	321	1,293	1,111	618	238	2
Hudspeth	0	0	0	0	0	0
Hunt	70	128	118	88	71	58
Hutchinson	174	240	206	213	221	233
Irion	366	1,176	1,097	674	295	21
Jack	2,091	2,008	857	363	405	450
Jackson	22	45	56	42	28	13
Jasper	0	0	0	0	0	0
Jeff Davis	0	0	0	0	0	0
Jefferson	157	180	202	230	280	315
Jim Hogg	30	60	75	56	37	17
Jim Wells	23	45	57	42	28	13
Johnson	6,774	5,565	4,969	5,633	6,682	7,598
Jones	37	20	18	17	17	16
Karnes	20	1,153	1,399	1,117	834	551
Kaufman	2,452	2,788	3,289	3,998	4,908	5,648
Kendall	0	0	0	0	0	0
Kenedy	38	76	95	71	46	22
Kent	6	2	1	1	1	1
Kerr	71	76	80	100	102	111
Kimble	1	2	2	2	2	2
King	1,818	553	345	299	258	223
Kinney	0	0	0	0	0	0
Kleberg	305	329	342	326	310	294
Knox	1	0	0	0	0	0

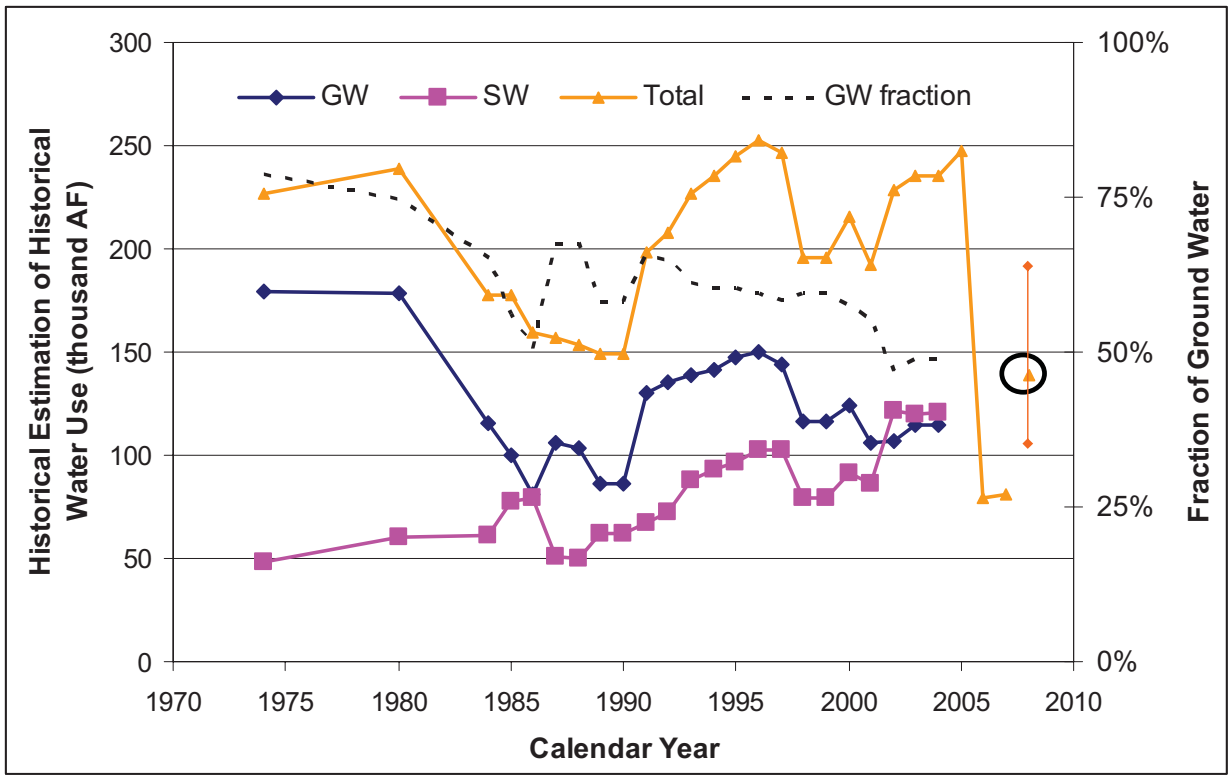
County	2010	2020	2030	2040	2050	2060
Lamar	0	0	0	0	0	0
Lamb	136	41	26	22	19	17
Lampasas	329	391	437	470	506	551
La Salle	280	2,989	4,300	3,398	2,570	1,742
Lavaca	25	621	1,839	1,638	1,276	914
Lee	2,089	2,547	5,749	5,772	5,715	5,659
Leon	678	1,680	2,701	2,431	1,732	1,034
Liberty	269	420	441	430	452	480
Limestone	2,500	7,333	6,258	5,630	5,242	4,928
Lipscomb	126	508	47	0	0	0
Live Oak	28	229	784	741	577	414
Llano	0	0	0	0	0	0
Loving	174	251	148	50	11	9
Lubbock	1,805	952	849	891	931	967
Lynn	273	214	128	59	29	25
McCulloch	4,219	7,690	7,073	5,324	4,274	3,460
McLennan	1,230	2,825	2,413	1,930	2,228	2,509
McMullen	30	2,154	3,383	2,682	2,038	1,395
Madison	0	278	865	775	607	438
Marion	24	665	728	494	259	33
Martin	588	1,279	1,103	622	247	10
Mason	560	1,023	941	708	568	460
Matagorda	31	61	77	57	37	18
Maverick	57	954	2,837	2,395	1,893	1,395
Medina	384	457	514	563	610	671
Menard	250	76	47	41	35	31
Midland	537	1,260	1,090	612	239	4
Milam	0	0	0	0	0	0
Mills	0	0	0	0	0	0
Mitchell	69	153	90	26	0	0
Montague	666	3,317	1,579	197	222	250
Montgomery	793	1,438	1,348	1,062	906	792
Moore	1	0	0	0	0	0
Morris	0	0	0	0	0	0
Motley	27	8	5	5	4	3
Nacogdoches	436	4,384	3,426	2,298	1,170	52
Navarro	77	97	124	156	198	236
Newton	140	256	235	177	142	115
Nolan	85	56	51	49	47	45
Nueces	556	699	837	934	1,009	1,118
Ochiltree	77	673	62	1	1	0
Oldham	182	207	246	277	289	315
Orange	233	304	309	308	309	314
Palo Pinto	464	2,632	1,174	3	3	2
Panola	2,095	3,700	3,507	2,815	2,123	1,500
Parker	4,489	2,398	840	821	952	1,098
Parmer	0	0	0	0	0	0

County	2010	2020	2030	2040	2050	2060
Pecos	102	769	2,132	1,648	1,280	926
Polk	0	0	0	0	0	0
Potter	576	692	859	1,016	1,108	1,254
Presidio	0	0	0	0	0	0
Rains	0	0	0	0	0	0
Randall	0	0	0	0	0	0
Reagan	679	1,640	1,420	796	310	3
Real	0	0	0	0	0	0
Red River	1	0	0	0	0	0
Reeves	431	1,815	3,330	2,362	1,742	1,270
Refugio	21	42	53	39	26	12
Roberts	183	447	41	0	0	0
Robertson	7,763	8,859	9,552	10,267	11,079	12,009
Rockwall	0	0	0	0	0	0
Runnels	60	18	11	10	9	7
Rusk	1,328	4,075	3,868	3,130	2,391	1,669
Sabine	268	2,327	1,816	1,244	674	102
San Augustine	435	3,044	2,152	1,431	711	31
San Jacinto	0	0	0	0	0	0
San Patricio	451	542	616	651	676	723
San Saba	280	511	470	354	284	230
Schleicher	52	137	127	78	35	4
Scurry	67	154	90	25	0	0
Shackelford	46	1,135	1,160	391	6	6
Shelby	616	4,540	3,335	2,225	1,114	62
Sherman	9	61	6	0	0	0
Smith	201	386	433	425	437	443
Somervell	1,373	1,251	945	813	810	830
Starr	202	292	376	416	456	510
Stephens	1,086	2,184	1,384	450	154	133
Sterling	119	406	328	170	61	1
Stonewall	154	61	46	42	38	34
Sutton	106	241	141	40	0	0
Swisher	0	0	0	0	0	0
Tarrant	4,669	2,799	1,665	1,577	1,525	1,484
Taylor	15	5	3	2	2	2
Terrell	149	132	78	34	15	13
Terry	84	156	91	28	3	2
Throckmorton	42	13	8	7	6	5
Titus	621	1,001	1,000	1,000	1,000	1,000
Tom Green	11	3	2	2	2	1
Travis	1,022	1,070	1,115	1,159	1,200	1,247
Trinity	0	0	0	0	0	0
Tyler	0	0	0	0	0	0
Upshur	7	605	988	694	400	105
Upton	744	1,776	1,522	842	321	0
Uvalde	59	72	78	81	86	93

County	2010	2020	2030	2040	2050	2060
Val Verde	59	96	83	68	65	72
Van Zandt	483	475	473	473	473	472
Victoria	23	46	58	43	28	14
Walker	488	660	842	1,086	1,337	1,572
Waller	0	0	0	0	0	0
Ward	145	347	323	179	112	90
Washington	22	391	1,166	1,051	831	612
Webb	475	1,934	2,296	1,995	1,705	1,425
Wharton	29	57	72	53	35	17
Wheeler	699	367	35	1	1	1
Wichita	12	4	2	2	2	2
Wilbarger	2	0	0	0	0	0
Willacy	16	31	39	29	19	9
Williamson	2,444	3,152	3,796	4,412	5,046	5,750
Wilson	0	474	1,473	1,320	1,033	746
Winkler	151	334	270	125	60	44
Wise	6,094	4,315	3,133	3,358	3,982	4,583
Wood	4	1	1	1	1	0
Yoakum	278	202	120	59	31	27
Young	40	604	621	238	49	52
Zapata	27	55	68	51	33	16
Zavala	0	550	1,712	1,494	1,169	845
SUM	**136,639***	**224,749***	**229,263***	**196,538***	**181,116***	**170,893***

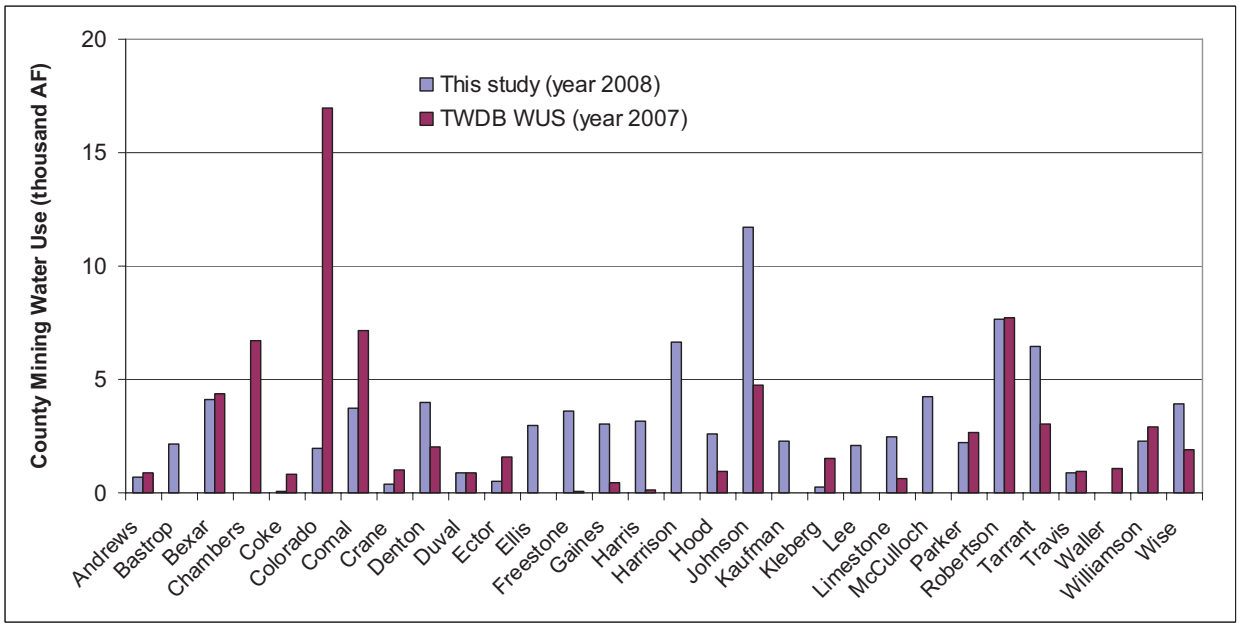
*: oil and gas drilling not included

MiningWaterUse2010-2060_2.xls



Source: TWDB website rptWaterUseSummaryByState_TWDB-WUS_1974-2004_+to 2007_JP.xls

Figure 134. Historical estimation of historical mining-water use
Most likely year 2008 water use is highlighted by the large circle. Also shown is the range of uncertainty.



MiningWaterUse2008_2.xls

Figure 135. Comparison of high mining water use

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8 Appendix List

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9 Appendix A: Relevant Websites

All categories
USGS mineral production: http://minerals.usgs.gov/minerals/
USGS water use: http://water.usgs.gov/watuse/
USGS e-library: http://pubs.er.usgs.gov/
U.S. Census Bureau: http://www.census.gov/econ/www/mi0100.html;
http://www.census.gov/mcd/
TWDB water use survey (WUS): http://www.twdb.state.tx.us/wrpi/wus/wus.htm
MSHA mine database (including abandoned mines): http://www.msha.gov/drs/drshome.htm
http://www.msha.gov/drs/asp/extendedsearch/statebycommodityoutput2.asp
EIA: http://www.eia.doe.gov/
BEG publications: http://www.beg.utexas.edu/publist.php

Aggregates:
Trade journals:
Aggregate Manager: http://www.aggman.com/
Pit & Quarry: http://www.pitandquarry.com/
Rock Products: http://rockproducts.com/
Mining Engineering: http://www.smenet.org/
Trade Associations:
National Stone, Sand, and Gravel Association (NSSGA): http://www.nssga.org/
TMRA: http://www.tmra.com/
TACA: http://www.tx-taca.org/

Oil and Gas:
Operators
Chesapeake: http://www.chesapeake.com/Pages/default.aspx
http://www.chk.com/Pages/default.aspx
Devon Energy: http://www.devonenergy.com
Barnett Shale Water Conservation & Management Committee:
http://www.barnettshalewater.org/
Trade Associations:
TXOGA: http://www.txoga.org/
Regulators:
RRC H10 query: http://webapps.rrc.state.tx.us/H10/h10PublicMain.do
Permit application: http://www.rrc.state.tx.us/forms/publications/HTML/index.php
All RRC forms: http://www.rrc.state.tx.us/forms/forms/og/purpose.php
Fresh-water questionnaire: http://www.rrc.state.tx.us/forms/publications/HTML/fw-ques.php
UIC query: http://webapps2.rrc.state.tx.us/EWA/uicQueryAction.do
RRC Barnett Sh.: http://www.rrc.state.tx.us/barnettshale/index.php
RRC Haynesville Sh.: http://www.rrc.state.tx.us/bossierplay/index.php
RRC Eagle Ford Sh.: http://www.rrc.state.tx.us/eagleford/index.php
USGS NOGA:
1995 assessment: http://energy.cr.usgs.gov/oilgas/noga/1995.html
Gulf Coast: http://energy.er.usgs.gov/regional_studies/gulf_coast/gulf_coast_assessment.html

Coal
CBM in Gulf Coast: http://energy.cr.usgs.gov/oilgas/cbmethane/pubs_data_gulf.html
RRC maps of coal resources: http://www.rrc.state.tx.us/forms/maps/historical/historicalcoal.php

RRC table of coal production: http://www.rrc.state.tx.us/data/production/index.php

Energy
Future of power generation in Tx: http://www.twdb.state.tx.us/RWPG/rpfgm_rpts.asp
Coal and uranium: http://www.rrc.state.tx.us/industry/smrd.php

Other useful sites:
Information about drilling rig count: http://www.rigdata.com/index.aspx;
http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm
IHS Energy: http://energy.ihs.com/
Drilling info: http://www.info.drillinginfo.com/
Aggregate industry: http://www.pitandquarry.com/pit-quarry-content/quarryology-101
IMPLAN by MIG, Inc.: http://implan.com/V4/Index.php

10 Appendix B: Postaudit of the 2007 BEG Barnett Shale Water-Use Projections

In the 2007 TWDB update of the Northern Trinity GAM (Bené et al., 2007), BEG (Nicot and Potter, 2007, summarized in Nicot, 2009a) proposed a methodology for estimating future water use related to Barnett Shale activities for 2 decades through 2025. The purpose of this appendix is to compare water-use projections with actual water use for the 2007–2009 (report used data through mid- to late 2006). At the October 2009 GSA meeting in New Orleans, Nicot and Ritter (2009) presented an initial postaudit, which is completed here.

2007 Report Methodology

The following steps are a summary of the methodology applied in the 2007 report:

Step 1: Derive the geographic extent in which frac jobs are likely to take place by integrating gas window, formation thickness, and well economics, defining high, low, and medium cases (somewhat subjectively).

Step 2: Use historical data to define average water use per well or per linear of lateral (Figure 136). Vertical well water use is nicely distributed along a normal distribution around a mean of 1.2 Mgal/well. Because defective database entries yielded unnatural water use at both low and high ends, averages used in the analysis are computed using data only between the 10^{th} and 90^{th} percentiles. The raw average and average of the values between the 10^{th} and 90^{th} percentiles for vertical wells is 1.25 and 1.19 Mgal, respectively. The raw average for horizontal wells (2005–2006) is 3.07 Mgal/well, whereas the truncated average is 2.65 Mgal/well. The relatively more abundant frac jobs with low water use (Figure 136a), generating a dissymmetric histogram result from the addition of acid jobs and other common well-development and completion practices outside of strictly defined frac jobs. In contrast to vertical wells that have a relatively narrow range of lengths/depths, horizontal wells have laterals of very variable length (although the vertical sections, as for the vertical wells, belong to a relatively narrow range) that translates into a more uniform distribution (Figure 136b). Only those frac jobs performed in 2005 and 2006 were included in the histogram of Figure 136b to avoid bias due to early trials of the slick-water frac technology. Using water-use intensity (volume of water per linear of lateral) instead of absolute water use per well yields a better-defined histogram (Figure 136c). The averages of values truncated beyond two complementary percentiles vary somewhat because of the additional uncertainty due to the lateral length, although a value of 2,400 gal/ft seems conservatively reasonable for the medium scenario. Values of 2,000 and 2,800 gal/ft were retained for low and high scenarios, respectively, for the 2007 report.

Step 3: Define a maximum water use at the county level by assuming that the county is drilled up and apply an average water use per vertical well or per linear of lateral. This step assumes a vertical well spacing of at least 40 acres (see Table 70 for details) and a constant distance between horizontal well laterals. All horizontal wells were assumed to be parallel to each other and to the main fault direction (under the assumption made at the time that operators would not want to drill through a large fault because of the risk of watering out the well). This assumption results in an extremely large water volume (Figure 137) that needs to be corrected and distributed through time.

Step 4: Apply time-independent correction factors: karst, operations, prospectivity. The sag avoidance ("karst") correction factor was assumed to take into account some reluctance from the operators to drill through disrupted Barnett Shale strata that was due to karstic features in the underlying Ellenburger Formation. Early on, in the vertical well phase, drilling to and

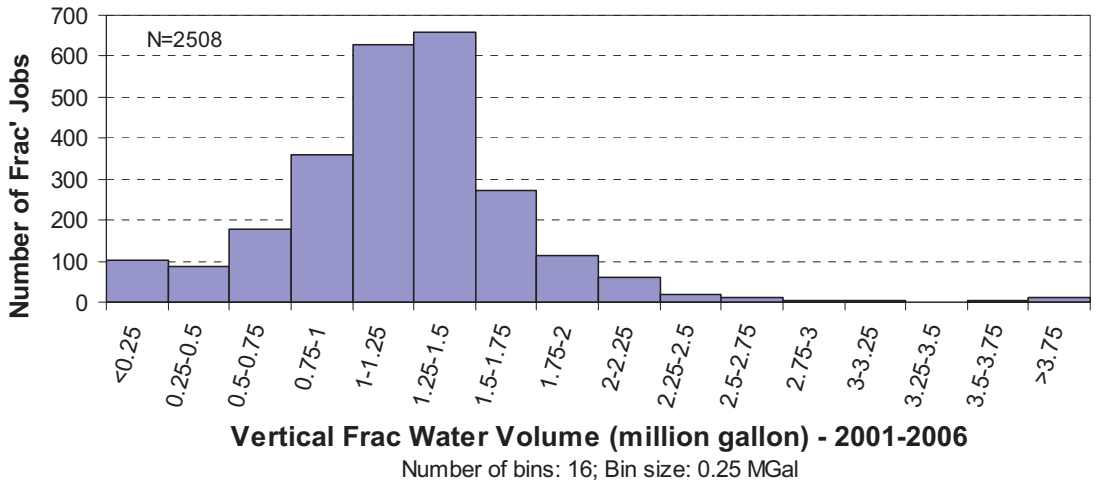
connection to the Ellenburger Formation was detrimental to operators because of excessive water production. The Ellenberger is a well-known regional (saline water) aquifer. It was thought at the time that operators would avoid karstic feature-rich areas because they were avoiding well-known faults. It turned out to be less of a concern than thought. Prospectivity represents the overall maturity of the shale and its likelihood to contain large economic resources in a given county or fraction of county. Prospectivity/risk factor can be understood either as a fraction of the area that will be developed or, more accurately, as the mean of the probability distribution describing the likelihood of having the county polygon developed (already given the high, medium, or low scenario condition). This factor is used simply as a multiplier of hypothetical maximum water use. The 2007 report used a prospectivity factor of 1 for core-area counties but one of 0.7 and 0.5 in Montague and Clay Counties, respectively. These oil-prone counties turned out to be more interesting than initially thought. The oil potential was thought to be not very prospective and, in fact, a hindrance to gas production.

Step 5: Add correction factors associated with time-dependent constraints. Growth of recycling techniques was assumed to reach a maximum of 20% of total water use in 2025. Recompletion/restimulation frequency remains unclear. The 2007 report assumes no recompletion for horizontal wells and that a large fraction of the vertical wells would be recompleted. The last and most controlling factor is the availability of drilling rigs. There are a limited number of active drilling rigs around the country, and their number at a given play is a complex function of play activity, oil/gas price, economic climate, relative location of other plays, etc. Galusky (2007) reported ~57 and ~93 active rigs in the Barnett Shale play in 2005 and 2006, respectively, resulting in 12 to 13 wells being drilled per year per rig, on average. The 2007 report assumes that there would be no more than 3,000 recompletions a year, starting in 2010 and ~2,400 in 2008, both in the "high" scenario case (Figure 138). This number turned out to be an underestimation in 2008. The actual number climbed to 2,500+ horizontal wells in 2008.

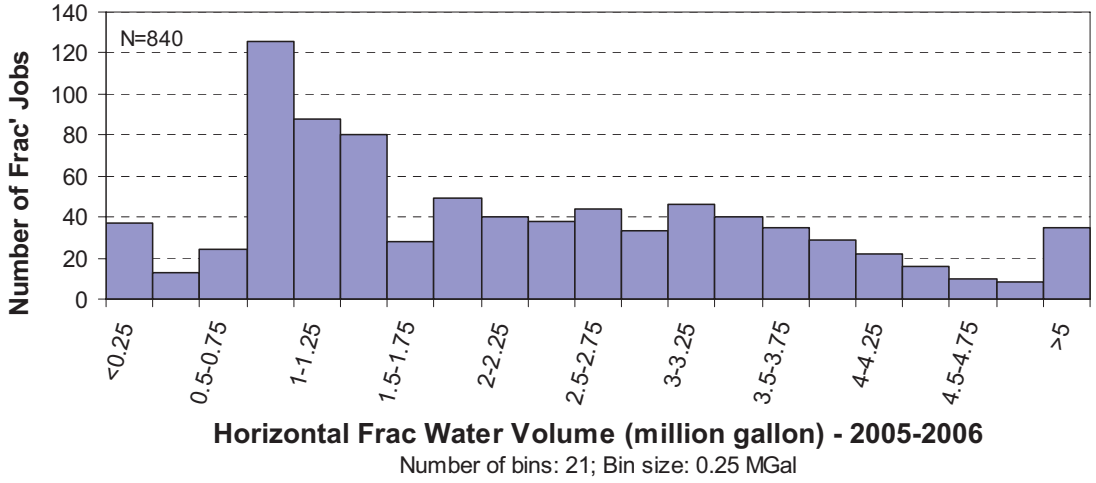
Step 6: Apply activity weighting curve to each county. This factor takes into account the life cycle of hydrocarbon production: initial production, relatively quick increase to peak production, peak sustained for a relatively short interval, relatively quick production, followed by a slow decrease. The 2007 report based the activity curve on that of Wise County that was on its past-peak decreasing limb in 2006 and applied it to all other counties or fractions of counties. Start date of each county activity was a function of geographic proximity to the core area and prospectivity.

Step 7: Apply GW/SW split. The 2007 report assumes increased reliance on groundwater. Groundwater use would reach 60% to 100% of total water use in 2025.

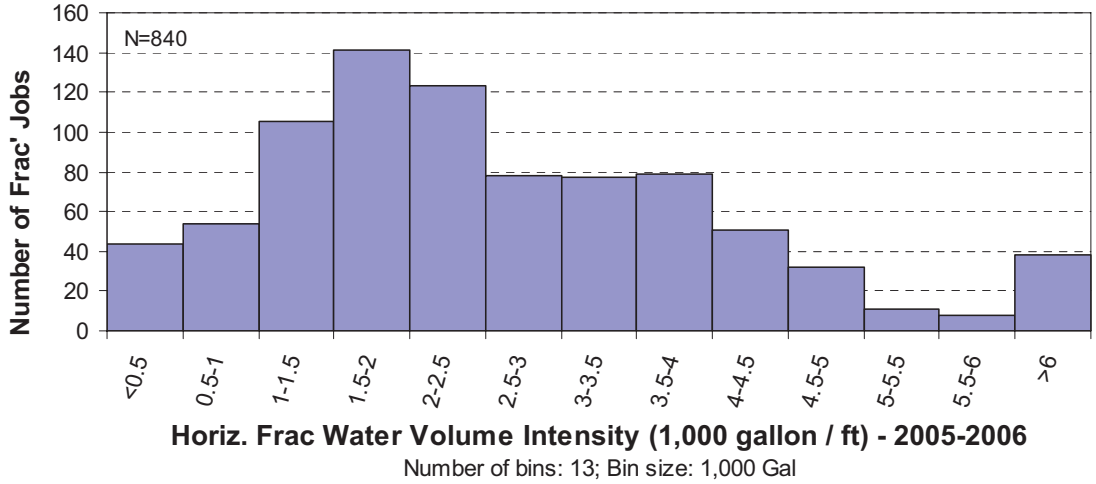
Resulting final output of the 2007 report is presented in Figure 139. The high scenario yields a total groundwater use of 417,000 AF, an annual average groundwater use of 22,000 AF over the 2007–2025 period, and a cumulative areal groundwater use of 0.05 AF/acre. The medium and low scenarios utilize a total 183,000 and 29,000 AF of groundwater for an annual average of ~10,000 and 1,500 AF and a cumulative areal groundwater use of ~0.04 and 0.009 AF/acre, respectively. A survey completed in the same period (Galusky, 2007) showed that projections were accurate in the short term and were bounded by the high and medium scenarios. The next section analyzes medium-term projections to the 2010 horizon and compares them to actual figures.



(a)



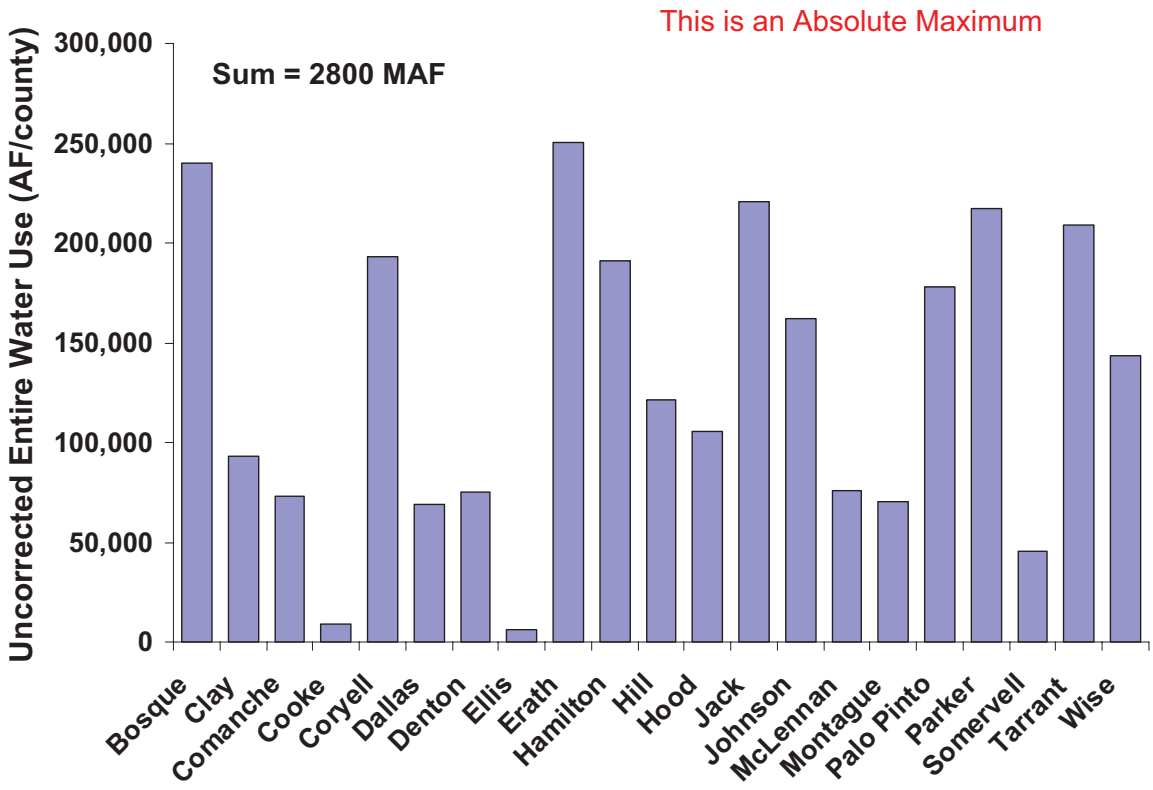
(b)



(c)

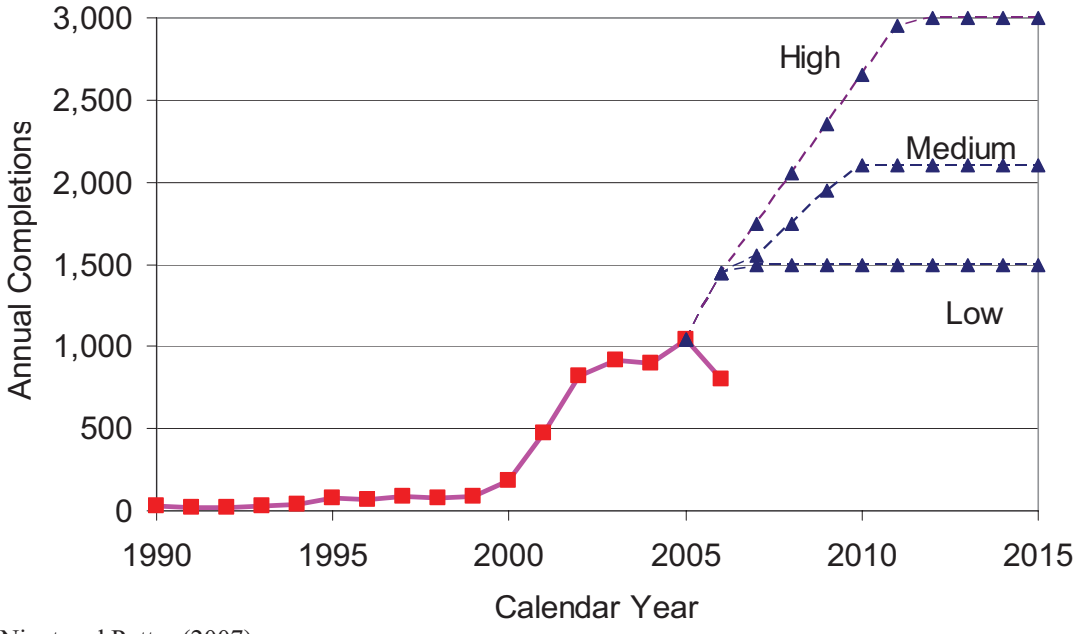
Source: Nicot and Potter (2007)

Figure 136. Distribution of water use for vertical wells (a), horizontal wells (b), and per linear of lateral of horizontal wells (c).



Source: Nicot and Potter (2007)

Figure 137. Uncorrected entire water use



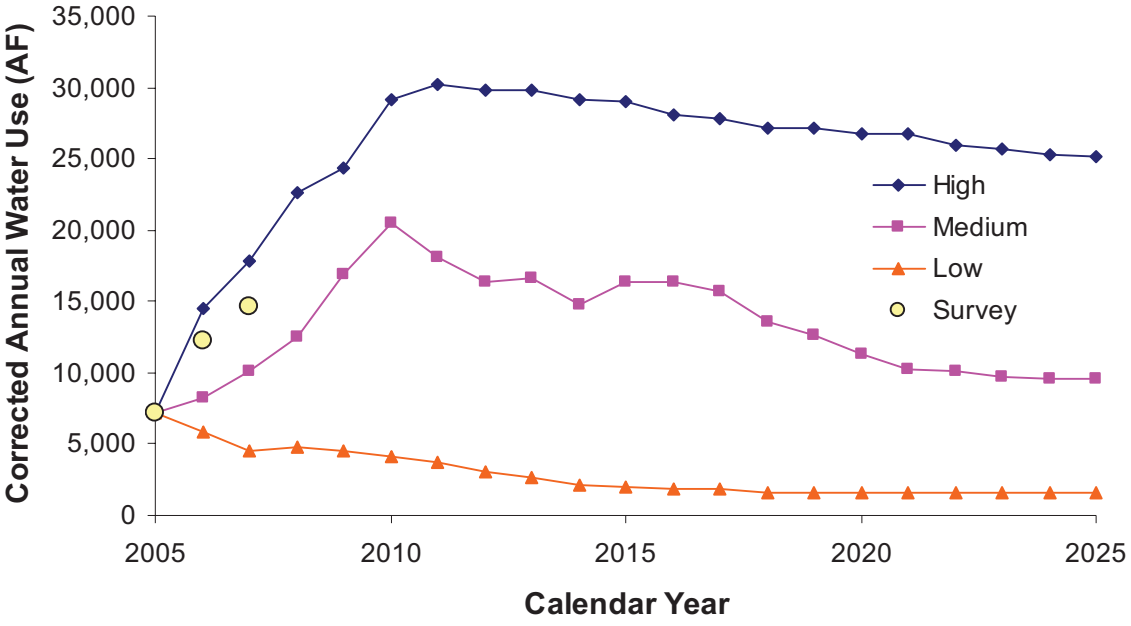
Source: Nicot and Potter (2007)

Figure 138. Projected annual completions

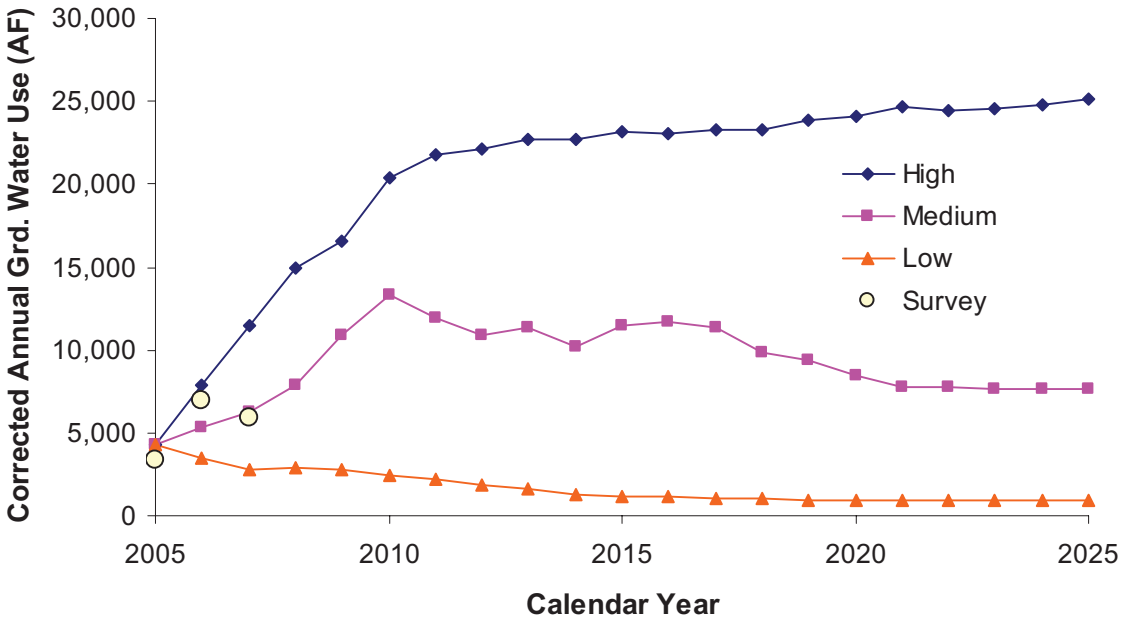
Table 70. Summary description of parameters used in 2007 report water-use projections

Category	Comment	High Water Use	Medium Water Use	Low Water Use
County Polygon	There are three binary variable couples: rural/urban—horizontal/vertical wells—within Viola footprint or not, resulting in four main categories: (1) Viola/urban (only horizontal wells), (2) Viola/rural (both horizontal and vertical wells), (3) no Viola/urban (only horizontal wells), and (4) no Viola/rural (only horizontal wells)			
Footprint Fraction	A county polygon cannot be covered by >90% (vertical wells) or 80% (horizontal wells) of the maximum possible well coverage.			
Vertical Well Spacing		1 well/40 acres	0.5 well/40 acres	0.25 well/40 acres
Horizontal Well Lateral Spacing	No Viola and/or urban	800 ft	1,000 ft	2,000 feet
	Viola rural	800 × 4 ft	1,000 × 4 ft	2,000 × 4 ft
Sag Feature Avoidance ("Karst")	Vertical well	100%		
	Horizontal well	100%	75%	40%
Average Water Use	Vertical well	1.2 million gal		
	Horizontal well (spread reflects uncertainty)	2,800 gal/ft	2,400 gal/ft	2,000 gal/ft
Water-Use Progress Factor[A]	(variations reflect technological progress)	1%	0%	0%
		Water-use annual incremental improvement as a fraction of total water use, e.g., 100% of current use in 2005 with a 1% increment translates into 80% of water use in 2025 compared with the same frac job executed in 2005		
Recompletion	Vertical well	100%	50%	0%
		of initial completions executed 5 years before		
	Horizontal well	0%	0%	0%
Recycling[A]		1%	0.33%	0%
		Recycling annual increment as a fraction of total water use (e.g., 0% in 2005 with a 1% increment translates into 20% recycling in 2025)		
Maximum Number of Sustained Annual Completions		3,000 completions/year	2,100 completions/year	1,500 completions/year
Additional Water Use in Overlying Formations		0%	0%	0%
Barnett Groundwater Use Expressed as % of Total Barnett Water Use	In year 2005–2006	60%	60%	60%
	Annual increment in following years	2%	1%	0%
	In year 2025	100%	80%	60%

Note: [A] These parameters do not maximize water use, but the likely competition for water in the high scenario suggests that recycling and water-use intensity will get better through time.
Source: Nicot and Potter (2007)



(a)



(b)

Source: Nicot and Potter (2007) and Nicot (2009a); survey data points by Galusky (2007)
Note: The data points used in a previous version of the same plot (Nicot, 2009a) are slightly lower because Galusky (2007) included drilling-water use. Nicot (2009a) was estimated at 20% of total water use whereas in this document, it is estimated at only 10%. "Survey" point for year 2007 in Galusky (2007) is also a projection but directed by data from the first few months of the year.

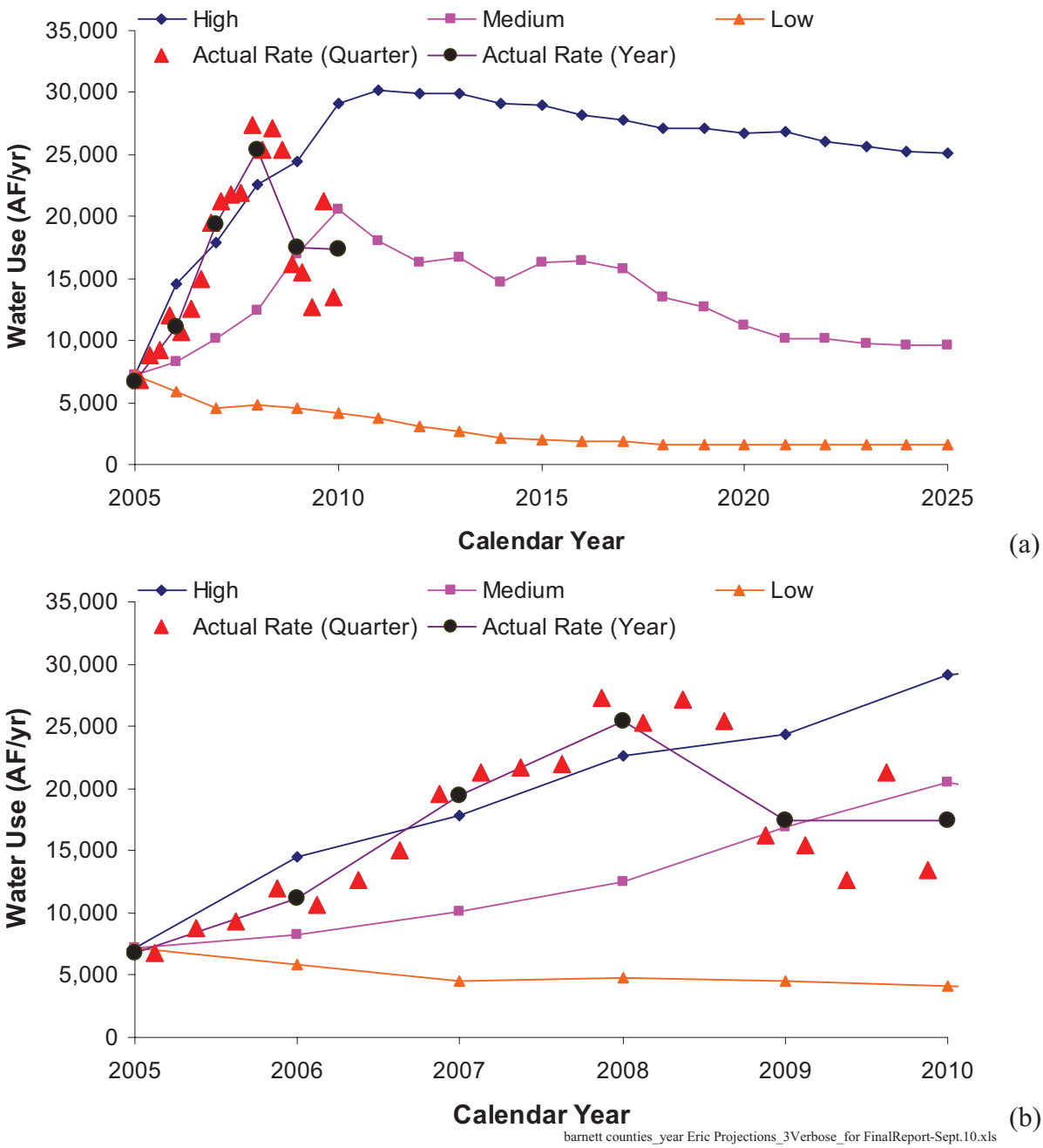
Figure 139. 2007 report projected frac total water use (a) and projected frac groundwater use (b)

Postaudit:

The recent downturn in gas prices has showed us that we cannot expect a linear development of the play but that it will go through periods of intense activity followed by calmer phases. I Because predicting these cycles is impossible in the long term, we only need to recognize that they exist and understand that actual water use will fluctuate around some projected average. Nicot and Potter (2007) suggested that peak water use (but not necessarily peak gas production) would occur around 2011 (Figure 140a, early years magnified in Figure 140b) after a quick ramp-up, followed by a slow decline. Superimposed on the projections are actual water-use figures as extracted from the IHS database in the summer of 2010. Initial growth overshot projections of the high scenario before crashing down below projected values of the medium scenario in 2009 because of the economic downturn. The figure depicts both quarterly water use (expressed in AF/yr) and annual values. Cumulative water use falls between high and medium scenarios (Figure 141).

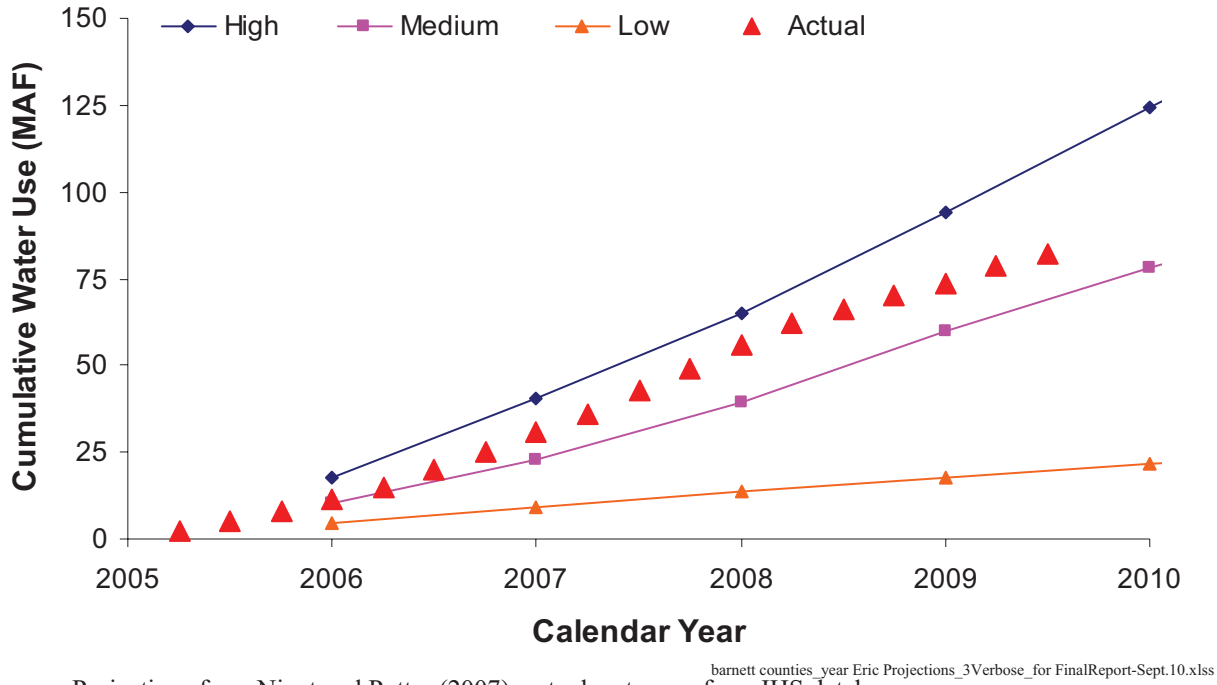
If the match between actual and projected numbers is good at the aggregate level, it is somewhat less so at the county level. Water use from four of the counties with significant figures (Denton, Johnson, Tarrant, and Wise) are plotted in Figure 142. Individual county matches are acceptable, but trends are better preserved by aggregating the four counties. A cross-plot comparison at the county level (Figure 143) also suggests that the general trend was well captured regionally but that deviations exist at the county level. Comparison of actual data is made against the high scenario in Figure 143a (linear scale) and Figure 143b (log scale). The high scenario was constructed as bounding—that is, most of the points should be below the unit slope line. Neglecting the 2009 points, they are for the most part. The 2009 points are located above the line (projected > actual) because of the economic downturn.

Several important conclusions can be drawn from this exercise: (1) it is possible to make sensible projections, at least at a 5-year horizon; (2) projections deviate from actual values as the size of the area of interest decreases— county-level projections seem to be noisy and more uncertain than projections made for larger geographic areas; (3) county-level projections can be off by a factor of 2 or more, even if projections are acceptable at the aggregate level.



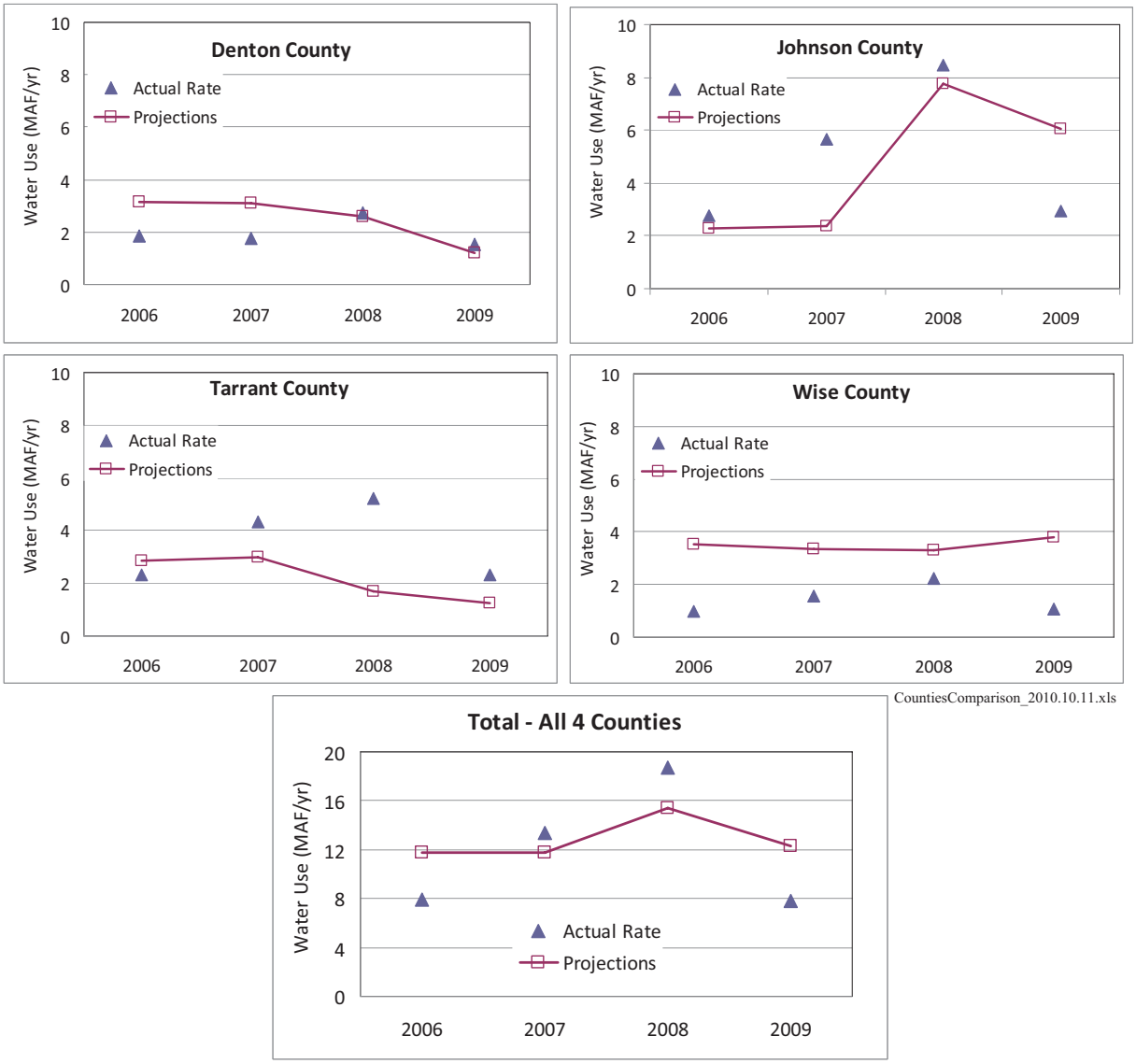
Source: Projections from Nicot and Potter (2007); actual water use from IHS database
Note: Tick for calendar year corresponds to the middle of the year (06/30); water use for each quarter (expressed in AF/yr) of a given year is on both sides of the calendar-year tick; 2010 yearly water use assumed that overall water use for the year will stay as in the first 2 quarters.

Figure 140. Comparison of water-use projections and actual figures in the Barnett Shale (2005–2010)



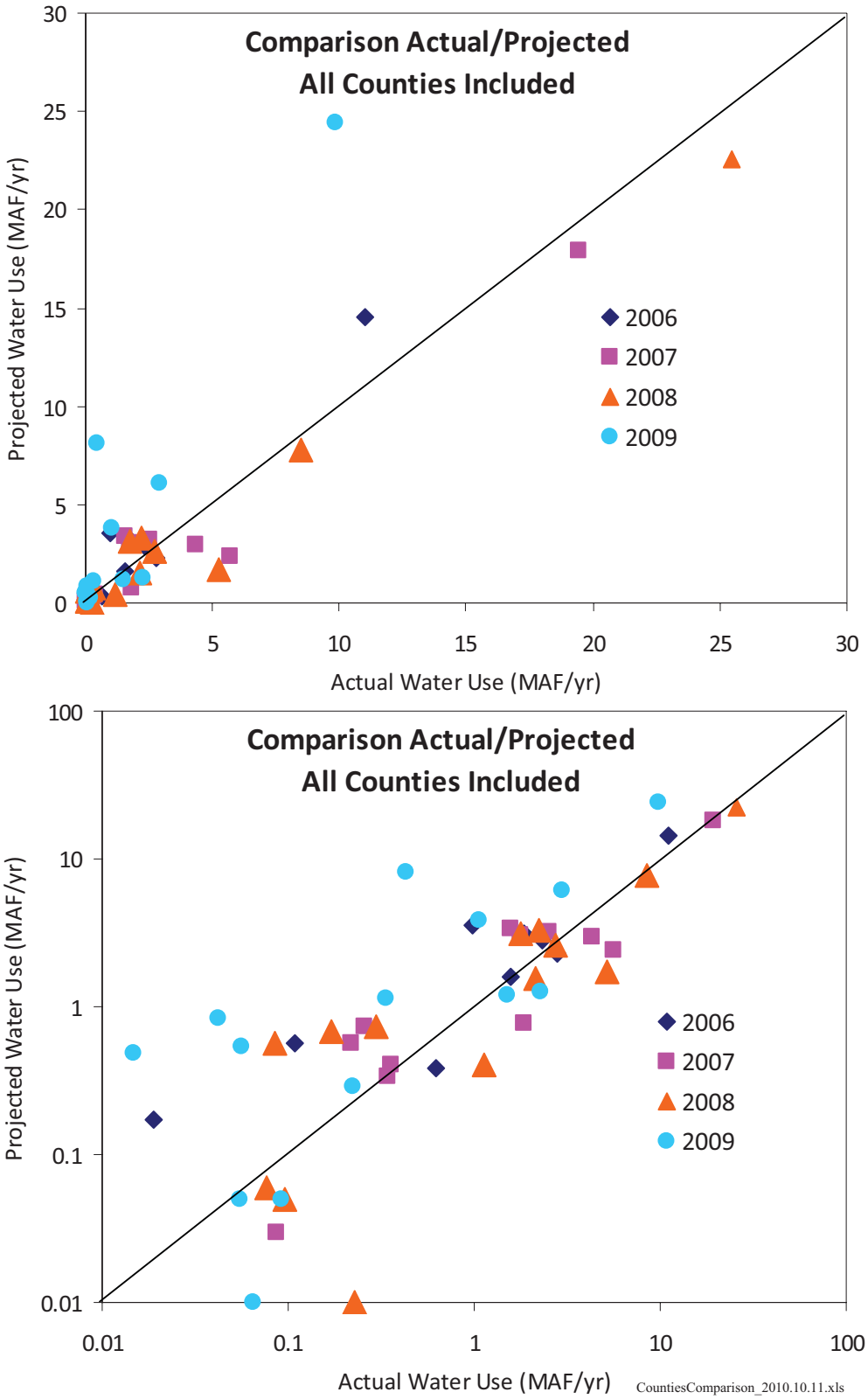
Source: Projections from Nicot and Potter (2007); actual water use from IHS database
Note: Tick for calendar year represents the end of the year (12/31); origin of both projection and actual water use is set on 01/01/2006; MAF = thousand AF

Figure 141. Comparison of cumulative water-use projections and actual figures in the Barnett Shale (2006–2010)



MAF = thousand AF

Figure 142. Comparison of actual vs. projected (high scenario) water use for four counties: Denton, Johnson, Tarrant, and Wise.



MAF = thousand AF

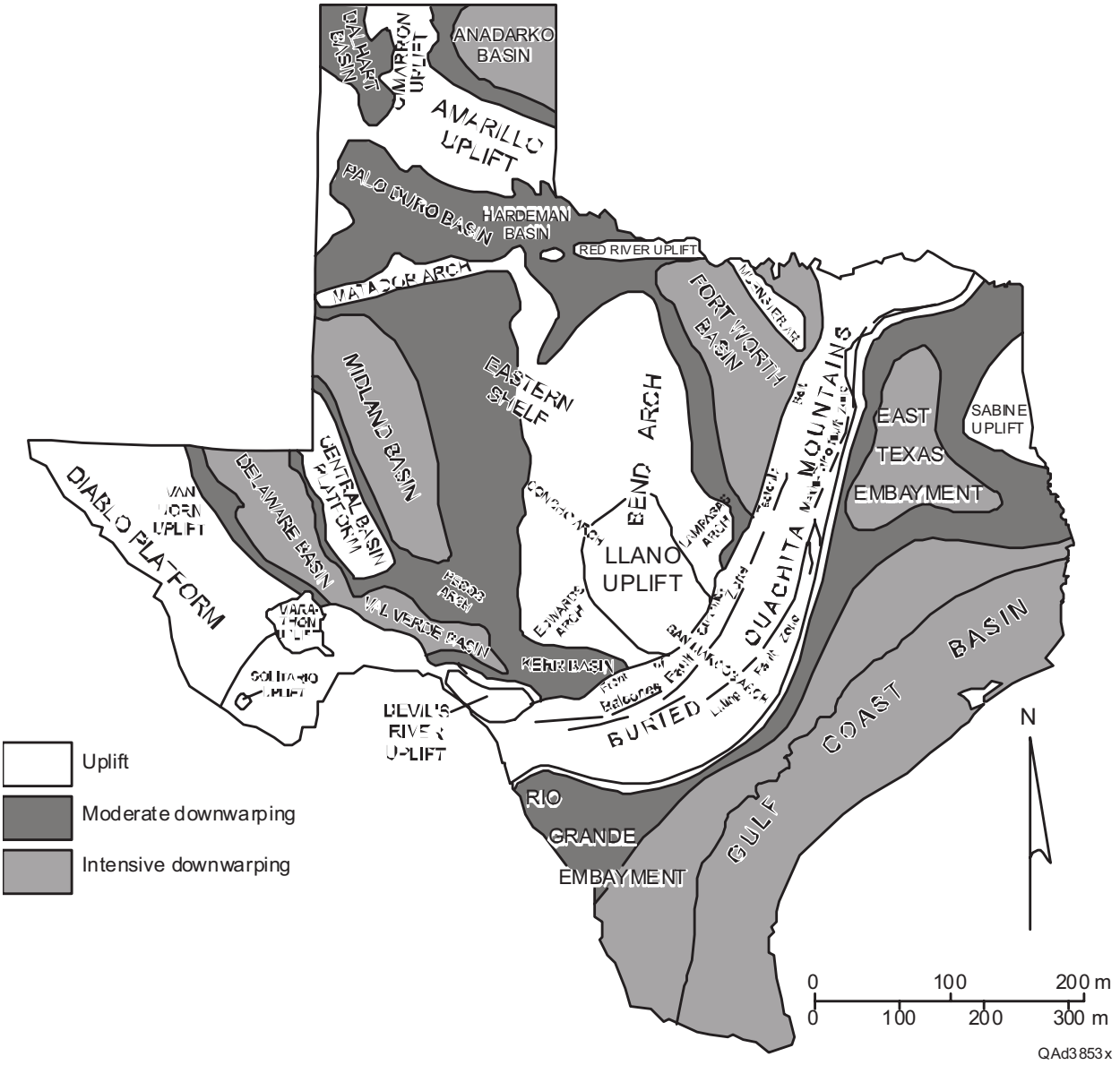
Figure 143. Comparison of actual vs. projected (high scenario) water use for all Barnett Shale counties

10 Appendix C: Relevant Features of the Geology of Texas

This appendix provides an overview of the geology of Texas at it applies to hydrocarbon accumulations summarized from Ewing (1991). The state can be divided into basins (Figure 144). Most of West and Central Texas is underlain by Precambrian rocks that crop out mostly in the Llano Uplift in Central Texas and locally in the Trans-Pecos area. Starting in the Cambrian period, ~550 million years ago, failed continental rifting resulted in widespread deposition of shelf sediments on a stable craton (e.g., Ellenburger Group). Carbonate and clastic deposition continued until the late Devonian, 350 million years ago. Thickness of the deposits varies, with a maximum in the ancestral Anadarko Basin and total removal by erosion of some formations along a broad arch oriented NW-SE on the Amarillo-Llano Uplift axis. Beginning in the Mississippian period (starting 350 million years ago), the passive-margin history of rifting and subsidence was replaced by extensive deep-marine sedimentation and tectonic convergence on the eastern flank of the continental margin. This convergence episode yielded the so-called Ouachita Mountains, now eroded and buried, whose trace approximately follows the current Balcones Fault Zone that runs west from San Antonio and northeast through Austin to the east of Dallas. Behind the orogenic belt, during and after the compressive event, sedimentation continued in and around several inland marine basins, north and west of the current Balcones Fault Zone. Sedimentation was thicker in the basins and thinner or absent on platforms and arches. During these times (320– 270 million years ago) major subsidence and sediment accumulation, partly fed by the erosion of the Ouachita Mountains, occurred in the Permian Basin, including the Delaware and Midland Basins separated by the Central Platform Uplift. Farther north, the Anadarko Basin is separated from the Midland Basin by another basin and two structural highs. The Anadarko Basin also underwent abundant sedimentation during the Pennsylvanian and Permian and included coarse granitic detritus (“granite wash”) from the Amarillo Uplift. The Fort Worth Basin is also filled with Pennsylvanian and Permian sediments.

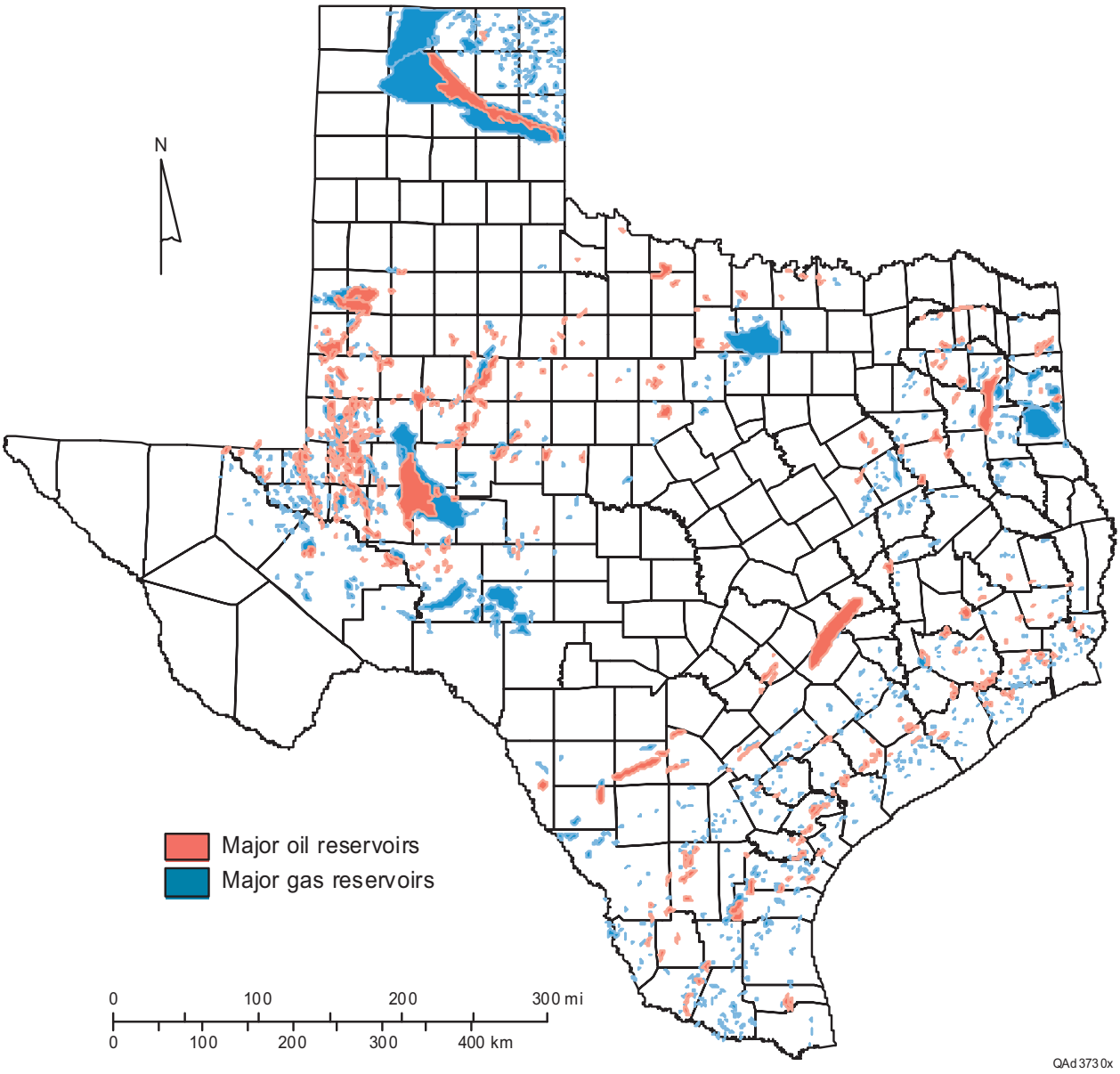
Beginning in Triassic time (250 million years ago), Texas was again subject to extension and volcanism, leading to Jurassic rifting of the continental margin and creation of the Gulf of Mexico and Atlantic Ocean. The focus of major geologic events shifted to the eastern part of the state. The small rift basins that initially formed were buried under abundant salt accumulation (Louann Salt). As the weight of sediments increased, the salt became unstable and started locally to move upward in diapirs, a phenomenon still locally active today. During the Cretaceous, sediments deposited from shallow inland seas formed broad continental shelves that covered most of Texas. Abundant sedimentation in the East Texas and Maverick Basins occurred during the Cretaceous. In the Tertiary (starting 65 million years ago), as the Rocky Mountains to the west started rising, large river systems flowed toward the Gulf of Mexico, carrying an abundant sediment load, in the fashion of today’s Mississippi River. All the area west of the old Ouachita Mountain range was also lifted, generating a local sediment source, including erosional detritus from the multiple Tertiary volcanic centers in West Texas and Mexico. Six major progradation events, where the sedimentation built out into the Gulf Coast Basin, have been described.

Many Texas basins contain hydrocarbons (Figure 145). Their stratigraphy is detailed for oil and gas productive formations in Figure 146 and Figure 147 for the Gulf Coast and East Texas Basins and in Figure 148 and Figure 149 for the North-Central and West Texas Basins.



Source: modified from Kreitler (1989)

Figure 144. Generalized tectonic map of Texas showing location of sedimentary basins



Source: BEG map from Galloway et al. (1983) and Kosters et al. (1989)

Figure 145. Map of major oil and gas fields in Texas

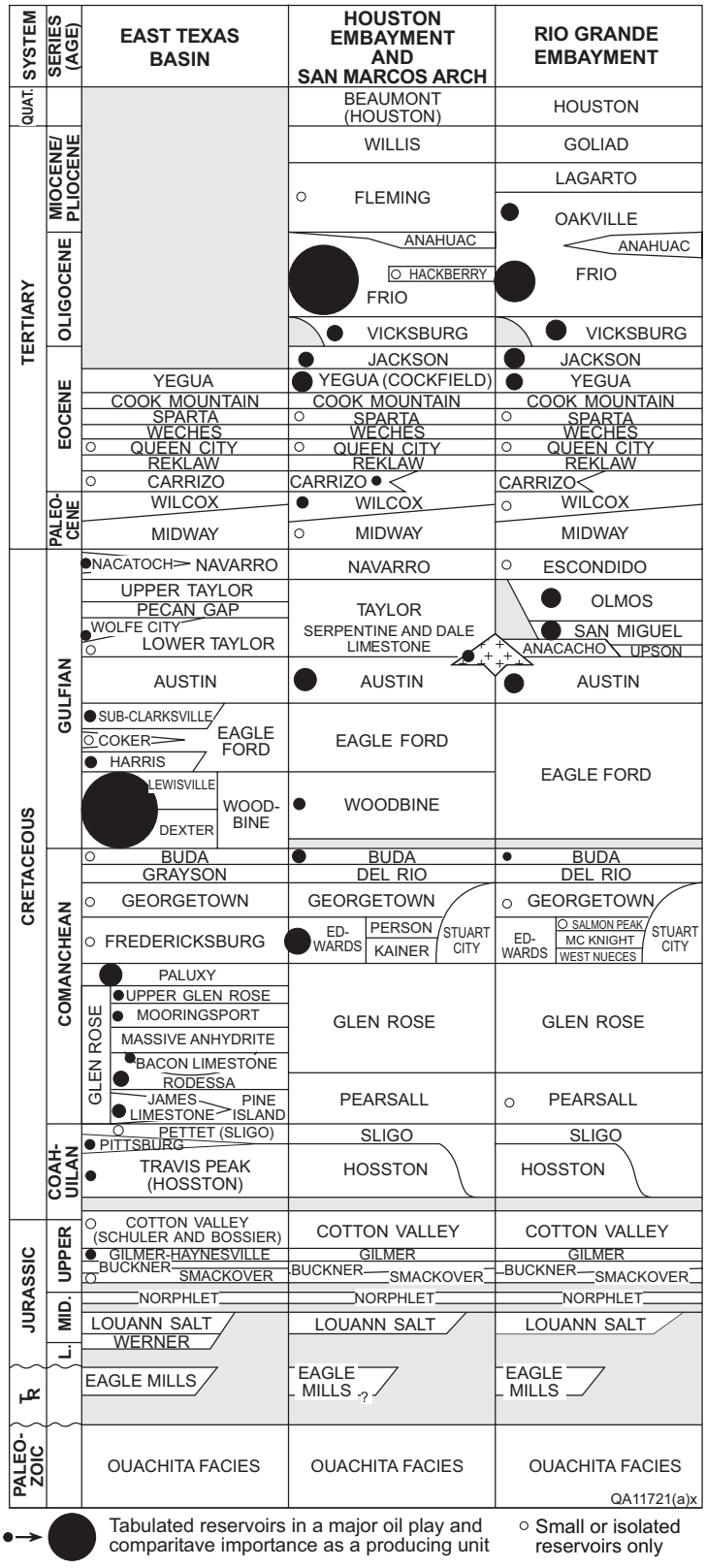


Figure 146. Stratigraphic column and relative oil production for the Gulf Coast and East Texas Basins (after Galloway and others, 1983)

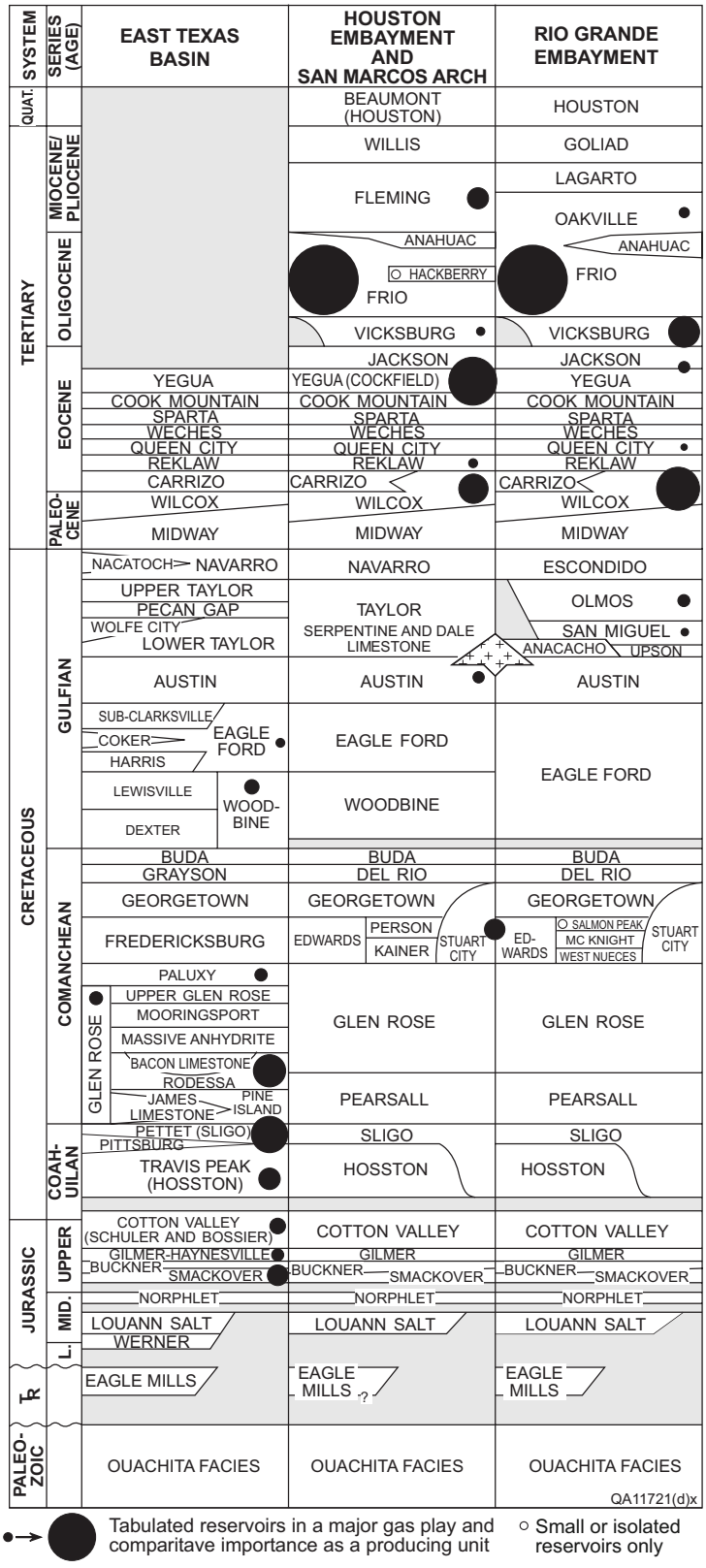


Figure 147. Stratigraphic column and relative gas production for the Gulf Coast and East Texas Basins (after Galloway and others, 1983)

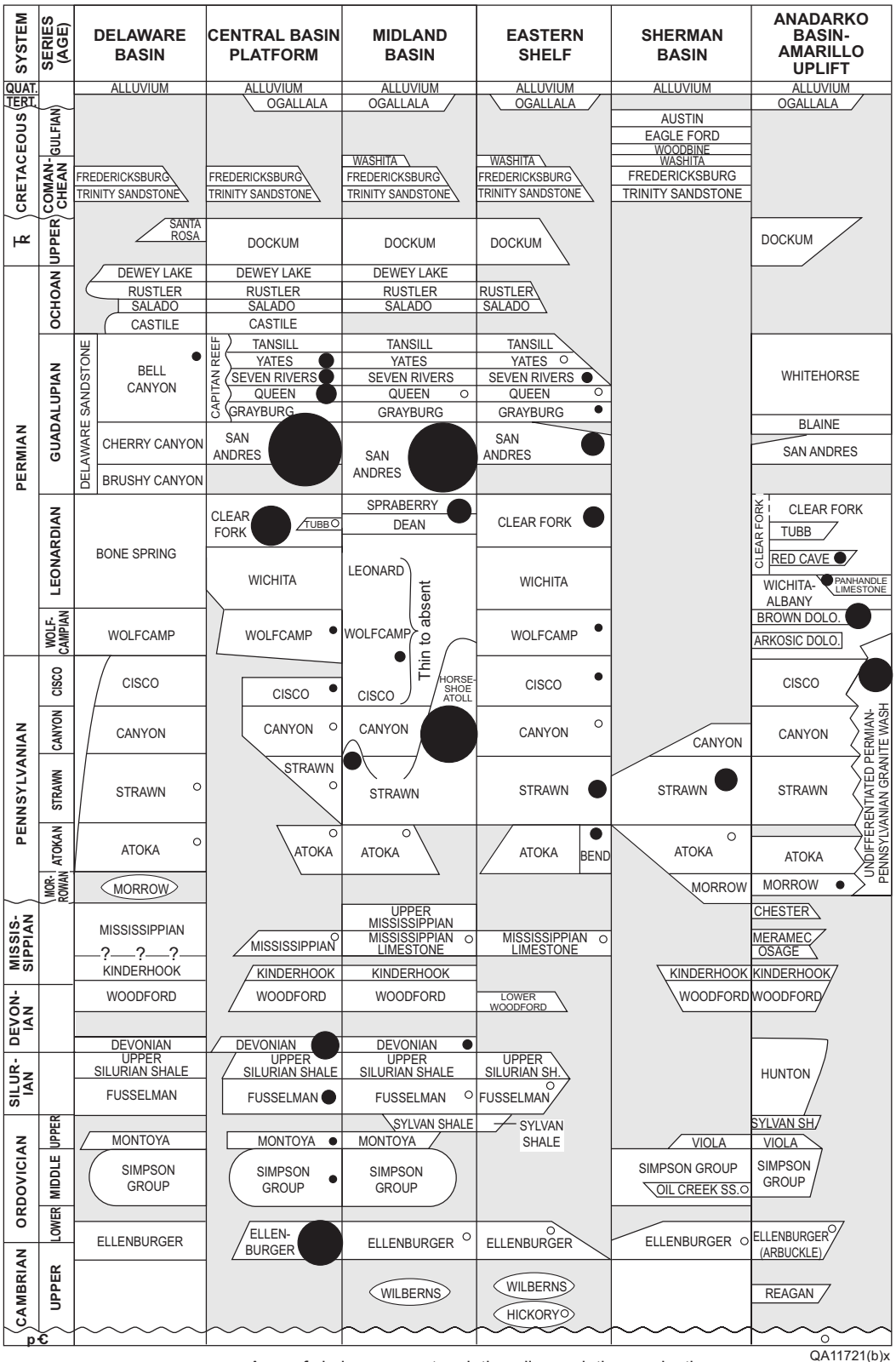


Figure 148. Stratigraphic column and relative oil production for the North-Central and West Texas Basins (after Kosters and others, 1989)

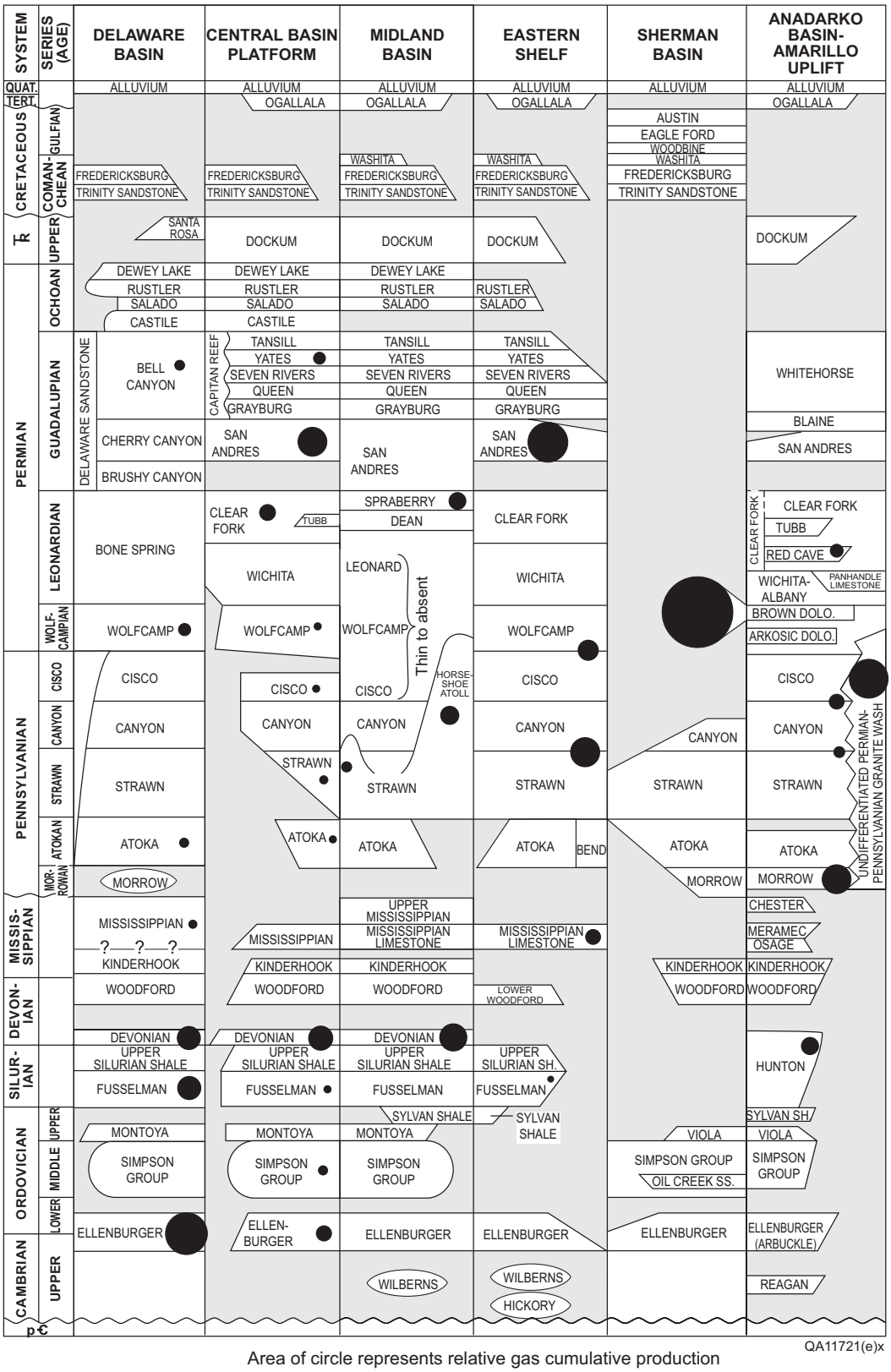


Figure 149. Stratigraphic column and relative gas production for the North-Central and West Texas Basins (after Kosters and others, 1989)

11 Appendix D: Survey Questionnaires

During the course of this study, we performed two types of surveys: (1) one aimed at water users through trade associations: TMRA and TACA, and (2) one geared toward water suppliers/Groundwater Conservation Districts (GCDs). We performed an additional survey of oil operators in Texas to inquire about their waterflooding activities.

11.1 Survey of Facilities

As part of this study, we enlisted the assistance of two of the major associations representing the mining industry in Texas: the Texas Aggregate and Cement Association (TACA) and the Texas Mining and Reclamation Association (TMRA). With the endorsement of each association, letters were sent on behalf of the TWDB to all of the association member companies with a survey form. Forms were provided as both Word documents with narrative questions and as Excel documents in spreadsheet format. Examples of the forms are given at the end of this appendix. Survey questionnaires were sent to TMRA members in December 2009, and the association asked that all responses be returned for review of sensitive or proprietary information. Company survey questionnaires were sent to TACA members in February 2010 and handled the same way.

11.1.1 About the Trade Associations

The Texas Mining and Reclamation Association (TMRA) has a variety of members—in addition to individual members and consultancy, its membership includes the following companies: Clay Mining: Acme Brick Company, Boral Bricks, Inc., Elgin Butler Company, Southern Clay Products, U.S. Silica Company; Utilities/Lignite/Coal Mining: Luminant Mining, North American Coal Corporation, Texas Westmoreland Coal Company, Walnut Creek Mining Company, American Electric Power, NRG Energy, San Miguel Electric Cooperative, Inc., Texas Municipal Power Agency; Sand, Gravel and Stone Mining: Capitol Aggregates, LTD, Hanson Aggregates Central, Inc., Trinity Materials Company, Chemical Lime Company; and Uranium Mining: South Texas Mining Venture, Mestena Uranium, LLC, Rio Grande Resources Corporation, Signal Equities, LLC, Uranium Energy Corporation, Uranium Resources, Inc.
The Texas Aggregate and Cement Association (TACA) does not release the list of its membership but does include many small aggregate producers.

11.1.2 Response Rates

Aggregates: 6 companies representing 27 sites provided responses to the BEG. Complete responses are provided in Appendix G and include

Coal/Lignite: we received information back from all lignite mines in Texas (~100% success rate)

Uranium: we received information from several operators

11.2 Survey of GCDs

LBG-Guyton was charged with the task of researching and evaluating groundwater use for mining in Texas. We compiled a packet of the mine data that we were able to obtain through statewide public sources to send to all GCDs so that they might address any changes to water usage that they might be aware of. To begin with, a series of maps and tables of mineral mine data and locations throughout Texas were produced so that each district could see what data were available publicly. These maps and tables were included in a mailed packet, along with a survey requesting any mining information the district had available, an explanation of the data included

in the packet, and a letter explaining the purpose of the study. The GIS maps contain all Texas GCDs and mine locations (active and inactive) in the TCEQ SWAP project database, and the data tables include mine data from MSHA and mining water-use projections from TWDB's 2007 *Water for Texas Report*.

Forty-seven (47) out of one hundred (100) questionnaires (47%) that were sent to GCDs were returned. Figure 150 is a map showing the districts that replied, as well as the mine sites that the TCEQ report lists as active in the state of Texas. Districts that replied to the survey are colored and labeled; all other districts are gray. Questions included in this packet are predominantly yes or no questions with requests for explanations of the answers if confirmed. The questions are listed in Table 71, with the answer percentage (using only those 47 GCDs that returned responses). In addition to the leading questions, explanation was requested if the answer was reported as yes. Studying these comments helped us discover some general findings among the survey questionnaires returned. In general, we found that few GCDs had extensive knowledge of mineral mining or mining water use within the district. Some districts had a general idea of what mining operations were active and inactive and could speculate as to how much water was being used according to permits, but none of the districts monitored actual water use.

Also, more districts thought that water use from mining data that had been reported in the TWDB report (such as presented in Table 75) was incorrect, excluding those that did not know. Few had contacted any of the mining entities, and even fewer had contacted the RRC to obtain data on mines. However, nine districts did report some quantitative knowledge of permitted volume of water use for specific mining entities. Table 72 details TWDB water use for mining WUG predictions from 2010 through 2060 and each of the district's own reported volumes for comparison.

Table 71. GCD mine-data questions and response percentages

Question	Total Answers	% Yes	% No	% Unk†	% >0
1. Does your district independently estimate water use by mining?	45	16 %	84 %		
2. Have you contacted Texas Railroad Commission to obtain data on mines?	45	4 %	96 %		
3. Do you have any way of validating the mining use estimates in Table 3?	45	18 %	82 %		
4. What portion of total water use in your district is used for mining?*	36			42 %	36 %
5. Have you contacted any of the entities listed in Table 1 or 2?	44	14 %	86 %		
6. Do you feel the data in Table 3 are accurate?	45	9 %	18 %	73 %	
7. Do you know of other mining facilities not included on the map?	43	9 %	91 %		
8. Do you have any additional information regarding groundwater or surface water use at the facilities?	40	15 %	85 %		

† Unknown—answered "Don't know"
*18 % reported 0 % water use for mining

Table 72. Mining water-use changes reported by certain GCDs

GCD	Volume (ac-ft)							Ratio of Reported/ Predicted 2010 Values	District Notes
	2010	2020	2030	2040	2050	2060	District Reported		
Barton Springs/Edwards Aquifer CD	1699	1821	1902	1982	2060	2116	826	49%	District-reported mine water use reported as industrial WUG.
Bee GCD	36	40	42	44	46	48	**105	292%	**% water use (201 ac-ft) split between Bee Co. and Live Oak Co. not specified so was assumed to be half for this exercise.
Harris-Galveston Subsidence District	1547	1713	1815	1917	2020	2112	25	2%	Other water use reported as commercial or industrial WUG.
Headwaters UWCD	167	165	164	163	162	161	109	65%	
Hickory UWCD No. 1	394	395	396	397	398	400	4771	1211%	
Live Oak UWCD	3894	4319	4583	4845	5108	5341	**105	3%	**% water use (201 ac-ft) split between Bee Co. and Live Oak Co. not specified so was assumed to be half for this exercise.
Lost Pines GCD	10483	10485	10486	5487	51	52	4410	42%	Reported use by ALCOA in 2009 for lignite mining.
McMullen GCD	195	203	207	211	215	218	1	1%	
Post Oak Savannah GCD	4025	4024	4024	3024	1524	1524	15000	373%	ALCOA water use reported as industrial WUG. Water rights end in 2038.

*Of those districts that replied with volume calculations, ⅔ reported lower volumes of mining water use than in the 2007 state water plan

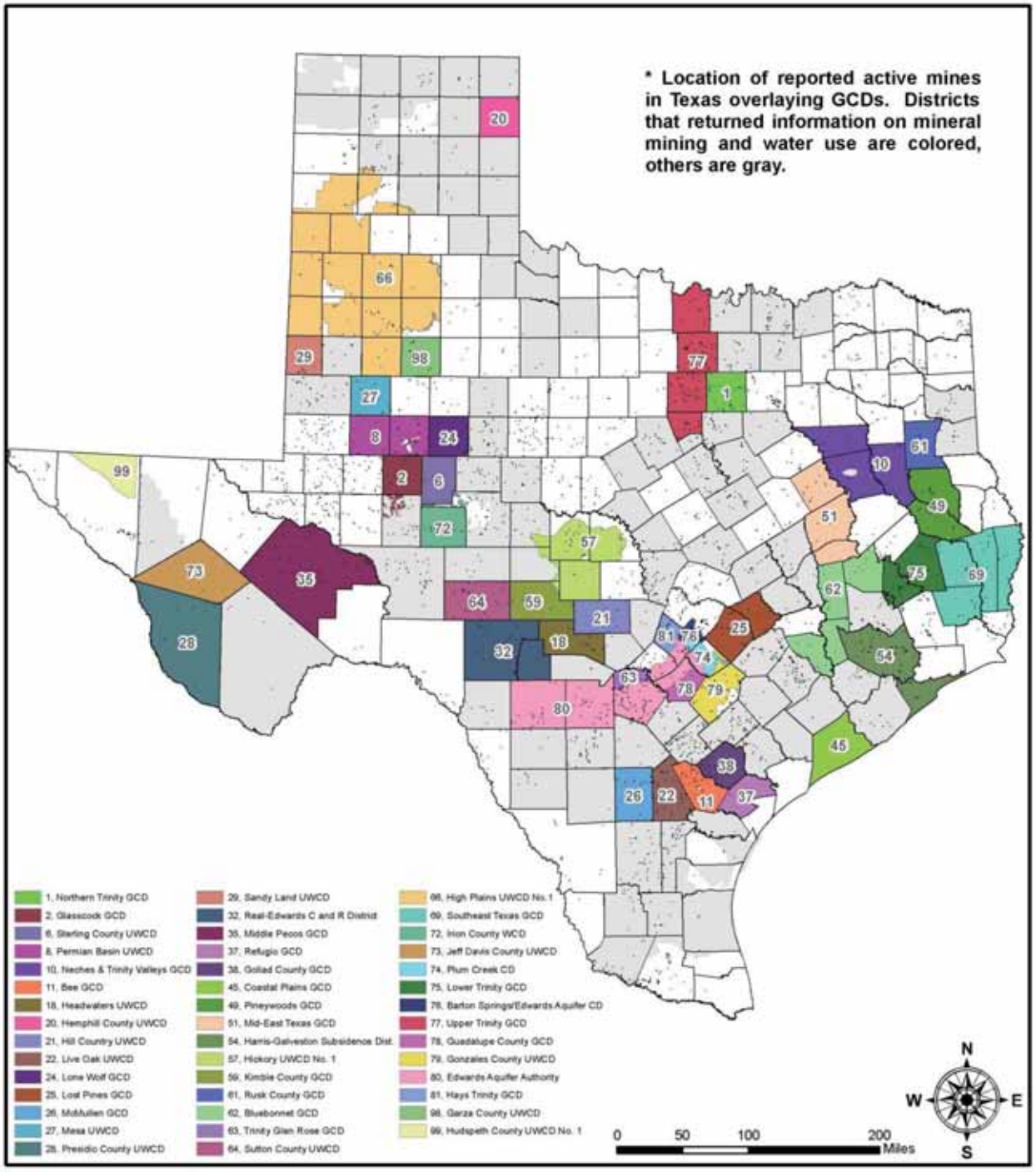


Figure 150. GCDs that have returned information on mineral mining water use in their district

11.3 Questionnaire Forms

To coal mining operators (modified to save space):

Date:
Name of Company and of Mining Operation (including SIC or SICs):
County of Mine Location:
Contact Name, Phone, E-mail, and Address:
Coal Production

1. Please rank factors affecting the amount of coal you produce from year to year in order from most (#1) to least important?

a. General economy (rank=)
b. Electricity demand projections (rank=)
c. Production capacity (rank=)
d. Other _____ (rank=)
e. Other _____ (rank=)

Water Source

1. Please indicate the approximate amount of water pumped each year as well as the unit used (acre-feet, gallons, etc.)

_____ (unit: _____)

2. Please circle the sources of the water pumped at your operations and indicate the approximate percentage of each applicable source:

a. Overburden dewatering (_____%)
b. Pit dewatering (_____%)
c. Depressurization (_____%)
d. Other _____ (_____%)

Choice (d) is intended for facilities at which additional water not ultimately originating from dewatering or depressurization is needed (e.g., river, another aquifer)

3. Please circle factors affecting the amount of water pumped? (check all that apply)

Dewatering
a. The amount of coal to be produced
b. Proximity to surficial aquifer
c. Other _____

Depressurization
a. The amount of coal to be produced
b. The safety factor to prevent floor heave
c. Proximity to aquifer
d. Other _____

Other
a. The amount of coal to be produced
b. Other _____

4. What is the quality (Total Dissolved Solids) of the water pumped at your operations for:

Dewatering
a. Fresh (<1000 mg/L)
b. Brackish (> 1000 mg/L and < 10,000 mg/L)
c. Saline (> 10,000 mg/L and < 35,000 mg/L)
d. Very Saline (> 35,000 mg/L)

Depressurization

a. Fresh (<1000 mg/L)
b. Brackish (> 1000 mg/L and < 10,000 mg/L)
c. Saline (> 10,000 mg/L and < 35,000 mg/L)
d. Very Saline (> 35,000 mg/L)
Other Source _____ *:*
a. Fresh (<1000 mg/L)
b. Brackish (> 1000 mg/L and < 10,000 mg/L)
c. Saline (> 10,000 mg/L and < 35,000 mg/L)
d. Very Saline (> 35,000 mg/L)
5. How often do you monitor the **rate and volume of water** pumped for depressurization/dewatering?
a. Daily
b. Monthly
c. Every 2-5 months
d. Yearly
e. Other:_____
6. How often do you monitor the **quality of water** pumped for depressurization/dewatering?
a. Daily
b. Monthly
c. Every 2-5 months
d. Yearly
e. Other:_____
7. Do you report the rate and quality of water pumped to a federal, state or local agency?
a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) _____

Water Use

1. For what specific mining activities do you consume the water pumped from dewatering/depressurization? (circle all that apply, provide approximate % if possible)
a. Dust suppression for mining (_____%)
b. Dust suppression for hauling (_____%)
c. Reclamation/revegetation (_____%)
d. Coal washing (_____%)
e. Transportation (_____%)
f. Drilling (_____%)
g. Other (please list) _____ (_____%)
2. Do you report the rate and quality of water consumed to a federal, state or local agency?
a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) _____
3. Do you supply water to other entities? Please circle all that apply.
a. None
b. Municipality (Name(s): _____)
c. Water supplier (other than municipality) (Name(s): _____)
d. Local farmers/ranchers/landowners

5. What factors affect whether or not pumped water is provided to these other entities? (circle all that apply)

a. Quality of water
b. Quantity and consistency of the amount pumped
c. Request from outside water users
d. Fee provided by outside water users
d. Other (please list) _____

Water Discharge

1. Where do you discharge the water not consumed during operations? (provide approximate percentage as needed)

Dewatering

a. Freshwater lake or stream (_____%)
b. Retention pond then lake or stream (_____%)
c. Deep-well injection (_____%)
d. Other _____ (_____%)

Depressurization

a. Freshwater lake or stream (_____%)
b. Retention pond then lake or stream (_____%)
c. Deep-well injection (_____%)
d. Other _____ (_____%)

Other Source

a. Freshwater lake or stream (_____%)
b. Retention pond then lake or stream (_____%)
c. Deep-well injection (_____%)
d. Other _____ (_____%)

2. Is the amount of water discharged monitored?

a. Yes
b. No

3. Do you report the monitored quantity to a federal, state or local agency?

a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) _____

Future of Lignite mining in Texas

1. Do you foresee any future developments in coal production that would make it more efficient or less water intensive? (Please list or describe any new technologies and the extent to which produced water would be decrease)

2. Do you expect water depressurization and dewatering pattern to remain the same over the short-term (1-9 years)?

a. Yes
b. No *If not, why?*

3. Do you expect water depressurization and dewatering pattern to remain the same over the long-term (10-50 years)?

a. Yes
b. No

If not, why?

To aggregate and other industrial mineral operators (modified to save space):

Date:
Name of Company & Mining Operation (including SIC or SICs):
County of Mine Location:
Contact Name, Phone, E-mail, and Address:

1) Please provide a brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated (flow charts are OK). Please separate, if possible, the industrial mineral mining operations from other product manufacturing (cement, brick, etc.) that may occur on the same property.

2) Water Amount and Water Use. Please report the amount (specify unit: gallons, acre feet, etc.) of water used, the amount recycled (actual or percentage), and the net amount consumed in mining operations annually (or another time unit, in all cases, specify).

   Please break this into amounts for each type of use (extraction, rock washing, roadway watering, dust suppression on conveyor systems, etc.), if possible.

   Please break this into amounts obtained from surface water, groundwater, storm water, etc. and name the source water (stream, lake, aquifer, etc.). Please also note the water quality (fresh, brackish, saline)

   Please report the amount of water typically used in rock washing equipment in gallons per minute/ton per hour (gpm/tph) of mineral product processed.

   Is water discharge out of the facility boundaries sometimes needed? When? How much? Which water type?

   Are these monitored or estimated values? Based on what years?

3) Production. Please report maximum aggregate, sand & gravel, or other industrial mineral mining production (in tons) authorized per year, and an estimate of the range of typical production in recent years. Is production expected to increase, decrease, or remain unchanged in coming years?

4) Future Water Use. How many years has the mine been in operation and what is the projected life of the facility? Are any new industrial mineral mining operations by your company anticipated (if so, where and when)?

   What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?

   What techniques or technologies could be utilized to reduce water use in the industrial mineral mining industry? Is use of saline or brackish water possible or likely to become more common?

   What are the key issues or challenges regarding water use being faced by your industry today or in the future?

To aggregate and other industrial mineral operators (alternate format in excel)

Name of Company & Mining Operation: Date:

County of Mine Location: Type of Mine/SIC:

Contact Name, Phone, E-mail, and Address:

Brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated.

	Quantity of Water Used (Total)	Quantity of Water Recycled	Quantity of Water Consumed (Lost)	Quantity of Water Used in Extraction	Quantity of Water Used for Rock Washing
fresh					
brackish					
saline					
	Quantity of Water Used for Roadway Watering	Quantity of Water Used for Dust Suppression	Quantity of Water Discharged if any	Where? How often?	Rate of Wash Water Use (gpm/tph)
fresh					
brackish					
saline					
	Surface Water (%)	Name of Water Source(s) (lake X, river Y, storm water, etc.)	Groundwater (%)	Name of Water Source(s) (aquifer X, local alluvium, etc.)	
fresh					
brackish					
saline					
	Product Name	Typical Production (tpy)	Authorized Production (tpy)	Number of Years of Mine Operation	Projected Life of Facility
Product1					
Product2					
Product3					

Is water use estimated or monitored? Which is the base year?

Is production expected to increase, decrease, or remain unchanged in coming years?

Are any new mineral mining operations by your company anticipated (if so, where and when)?

What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?

What techniques or technologies could be utilized to reduce water use in your industry? Is use of saline or brackish water possible or likely to become more common?

What are the key issues or challenges regarding water use being faced by your industry today or in the future?

To uranium operators (modified to save space):

Date:
Name of Company & Mining Operation (including SIC or SICs):
County of Mine Location:
Contact Name, Phone, E-mail, and Address:

1) Please provide a brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated (flow charts are OK). Please separate, if possible, the mining operations from other operations that may occur on the same property.

2) Water Amount and Water Use. Please report the amount (specify unit: gallons, acre feet, etc) of water used, the amount recycled (actual or percentage), and the net amount consumed in mining operations annually.

   Please break this into amounts for each type of use (subsurface ISR operations, surface ion exchange operations, dust suppression, etc.), if possible.

   Please break this into amounts obtained from surface water, groundwater, storm water, etc. and name the source water (stream, lake, aquifer, etc.). Please also note the water quality (fresh, brackish, saline)

   Please report the amount of water typically used/consumed (specify) in gallons per pound of product (specify U, U_3O_8, yellow cake, etc.) if possible.

   Is water discharge out of the facility boundaries sometimes needed (deep well injection during restoration)? When? How much? Which water type?

   Are these monitored or estimated values? Based on what years?

3) Production. Please report production or an estimate of the range of typical production in recent years. Is production expected to increase, decrease, or remain unchanged in coming years?

4) Future Water Use. How many years has the mine been in operation and what is the projected life of the facility? Are any new uranium mining operations by your company anticipated (if so, where and when)?

   What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?

   What techniques or technologies could be utilized to reduce water use in your industry? Is use of saline or brackish water possible or likely to become more common?

   What are the key issues or challenges regarding water use being faced by your industry today or in the future?

11.4 Survey of West Texas Oil Operators

For oil wells:

Water Use

		Fresh Water (<3,000 TDS)		Brackish Water (3,000–10,000 TDS)		Saline Water (>10,000 TDS)		
Item	**Unit**	**From GW**	**From SW**	**From GW**	**From SW**	**From GW**	**From SW**	**Notes/Explanation**
Water used in 2010 for well drilling	bbl							Project/estimate through 2010.
Water used in 2010 for well completion (& fracturing)	bbl							Project/estimate through 2010.
Water used in 2010 for waterflood operations	bbl							Project/estimate through 2010.
Water used for CO2 flood operations	bbl							Project/estimate through 2010.
Other substantial 2010 water use	bbl							Please note type of use and enter units as appropriate.

Operational Statistics				
Item	**Units**		**Notes/Explanation**	
No. **vertical** oil wells drilled in 2010	number		Estimate/project through year's end.	
Average well depth for **vertical** wells	ft		Estimate	
No. **horizontal** oil wells drilled in 2010	number		Estimate	
Average total lateral length for **horizontal** oil wells	ft		Estimate	
No. wells "fraced" in 2010	number		Estimate/project through year's end.	
Average depth/length of wells being "fraced"	ft		Estimate	
No. acres in active waterflood	number		Estimate	
No. acres in active CO2 flood	number		Estimate	
Estimated total 2010 oil production from waterfloods	bbl		Estimate	
Estimated total 2010 oil production from CO2 floods	bbl		Estimate	
Estimated total 2010 associated gas production from waterfloods	MMcf		Estimate	
Estimated total 2010 associated gas production from CO2 floods	MMcf		Estimate	

For gas wells

Water Use

		Fresh Water (<3,000 TDS)		Brackish Water (3,000–10,000 TDS)		Saline Water (>10,000 TDS)		
Item	Unit	From GW	From SW	From GW	From SW	From GW	From SW	Notes/Explanation
Water used for 2010 well drilling	bbl							Project/estimate through 2010.
Water used for 2010 well completion (& fracturing)	bbl							Project/estimate through 2010.
Other substantial 2010 water use	bbl							Please note type of use and enter units as appropriate.

Operational Statistics

Item	Units		Notes/Explanation
No. **vertical** gas wells drilled in 2010	number		Project/estimate through 2010.
Average well depth for **vertical** gas wells	ft		Estimate
No. **horizontal** gas wells drilled in 2010	number		Project/estimate through 2010.
Average total lateral length for **horizontal** gas wells	ft		Estimate
No. wells "fraced" in 2010	number		Estimate/project through year's end.
Average depth of vertical gas wells being "fraced"	ft		Estimate
Average total lateral length of horizontal gas wells being "fraced"	ft		Estimate

To GCDs:

Several figures and tables (following questionnaires) were sent to each GCD in Texas, along with the following questionnaire requesting information about the district's knowledge of mining operations within its borders.

When answering the following questions, we asked that GCDs not include water use for oil/gas activities.

1. Does your district independently estimate water use by mining?
    a. If yes – please describe
2. Have you contacted Texas Railroad Commission to obtain data on mines?
3. Do you have any way of validating the mining use estimates in Table 3? (*TWDB projections*)
    a. If yes – please describe method and result
4. What portion of total water use in your district is used for mining?
5. Have you contacted any of the entities listed in Table 1 or 2?
    a. If yes – please describe what you found
6. Do you feel the data in Table 3 are accurate?
    a. If yes – why?
    b. If no – why?
7. Do you know of other mining facilities not included on the map?
    a. If yes – do you have an estimate of the water use?
8. Do you have any additional information regarding groundwater or surface water use at the facilities?

In addition to figures similar to Figure 7 (Introduction section), we provided the GCDs with tables extracted from (1) the SWAP database (Table 73), (2) the MSHA database (Table 74), and (3) projections for the TWDB 2007 water plan for the counties included whole or in part in the GCD (Table 75). Only the last table gives some indication of mining water use.

Table 73. Example of information provided by the SWAP database (Lost Pines GCD)

Mine Sites in the Lost Pines GCD

PSOC ID	SITE ID	SITE NAME	LATITUDE (DD)	LONGITUDE (DD)	HORIZONTAL DATUM	LOCATION METHOD	AGENCY	ACTIVE	MINE TYPE	COMMODITY	GEOLOGIC FORMATION
4343	021BSW201		30.118900	-97.432800	27	MAP-M2	BEG	N		SAND, GRAVEL	WILLIS FORMATION
4344	021ELE301		30.363100	-97.268600	27	MAP-M2	BEG	Y		CLAY-COMMON	
4345	021ELE501		30.321899	-97.323303	27	MAP-M2	BEG	Y		CLAY-COMMON	
4346	021ELE502		30.332800	-97.292503	27	MAP-M2	BEG	Y		CLAY-COMMON	
4347	021ELE601		30.322201	-97.285301	27	MAP-M2	BEG	Y		CLAY-COMMON	
4348	021LAB401	Powell Bend	30.187500	-97.333336	27	MAP-M1	TNRCC	N	STRIP MINE	COAL-LIGNITE	CALVERT BLUFF FORMATION
4349	021LAB701		30.163601	-97.340797	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4350	021LAB702		30.156900	-97.339996	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4351	021PAI701		30.128300	-97.124199	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4352	021SMI201		30.091101	-97.200798	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4353	021SMI202		30.090000	-97.202202	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4354	021SMI901		30.015600	-97.164200	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4355	021SNW201		30.228300	-97.175598	27	MAP-M2	BEG	N		SAND, GRAVEL	REKLAW FORMATION
4356	021TOG201		29.988300	-97.169998	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4357	021TOG301		29.979200	-97.163300	27	MAP-M2	BEG	N		SAND, GRAVEL	WILLIS FORMATION
4359	021TOG303		29.988300	-97.129700	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4361	021TOG305		29.973600	-97.134697	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4362	021TOG306		29.975000	-97.137497	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4363	021UTY101		30.223600	-97.464699	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4364	021UTY401		30.208099	-97.490303	27	MAP-M2	BEG	Y		SAND, GRAVEL	ALLUVIUM
4365	021UTY601		30.175600	-97.413300	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4366	021WEP101		29.988100	-97.095802	27	MAP-M2	BEG	N	STRIP MINE	SAND, GRAVEL	ALLUVIUM
4367	021WEP102		29.987499	-97.099403	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
11080	287BEA701		30.411400	-97.250000	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	SIMSBORO SAND
11081	287BEA702		30.392799	-97.237503	27	MAP-M2	BEG	N	PIT	CLAY	SPARTA SAND
11082	287DIB201		30.343599	-96.805000	27	MAP-M2	BEG	Y	PIT	SAND, GRAVEL	YEGUA FORMATION
11083	287DIB202		30.343100	-96.796898	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	YEGUA FORMATION
11084	287DIB203		30.343300	-96.792503	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	YEGUA FORMATION
11085	287DIB204		30.342199	-96.795303	27	MAP-M2	BEG	Y	PIT	SAND, GRAVEL	YEGUA FORMATION

Table 74. Example of information provided by the MSHA database sent to GCDs

Texas MSHA Mine Database

Mine ID	Mine Name	Status	Type	Primary Commodity	Secondary Commodity	Operator Name	County	Street	PO Box	City	State	Zip	Nearest Town
4100249	Athens Plant & Pits	Intermittent	Surface	Common Clays NEC		Hanson Brick	Henderson	200 Athens Brick Road		Athens	TX	75751	Athens
4100252	Balcones Pit & Plant	Active	Surface	Common Clays NEC		Balcones Minerals Corp	Fayette	233 Balcones Lane		Flatonia	TX	78941	Flatonia
4100253	Barrett Base Plt	Active	Surface	Crushed, Broken Limestone NEC		Alamo Concrete Products Ltd	Bexar	6889 EAST EVANS ROAD		SAN ANTONIO	TX	782662813	San Antonio
4100262	Kosse Plant	Active	Surface	Common Clays NEC		U S Silica Company	Limestone	FM 2749		Kosse	TX	76653	Kosse
4100264	Standard Pit	Intermittent	Surface	Clay, Ceramic, Refractory Mnls.		Acme Brick Company	Bastrop	1776 Old McDade Road		Elgin	TX	78621	Elgin
				Common Clays		Elgin-Butler Brick							

Table 75. Example of information provided by the 2007 TWDB water plan sent to GCDs (Lost Pines GCD)

RWPG	County Name	WUG ID	WUG Name	Basin Name	TWD 2010	TWD 2020	TWD 2030	TWD 2040	TWD 2050	TWD 2060	Regional Comments
G	LEE	071003144	MINING	BRAZOS	5450	5450	5450	5450	13	13	
K	BASTROP	111003011	MINING	GUADALUPE	7	8	8	8	8	8	
K	BASTROP	111003011	MINING	COLORADO	5016	5018	5018	18	19	20	
K	BASTROP	111003011	MINING	BRAZOS	10	9	10	11	11	11	

12 Appendix E:
Supplemental Information Provided by GCDs

Some GCDs provided useful information. Some have already been mentioned in Appendix D (Table 72). As mentioned previously, few responses contained information useful to quantifying total groundwater usage by mining operations in Texas GCDs. However, a few are worth summarizing here because their account of groundwater usage varies from what is reported in the 2007 *Water for Texas Report*.

In addition, none of the GCDs located in the mining belt reported information regarding lignite mining. However, lignite mines and water use shown on the maps within these districts were not contested in any of the surveys we received. Five major areas in West Texas produce oil and/or gas: Andrews, Stephens, Hockley, Gaines, and Yoakum Counties. Three of these counties have a governing groundwater district: Hockley (High Plains UWCD), Gaines (Llano Estacado UWCD), and Yoakum (Sandy Land UWCD). We contacted these GCDs as well as Stephens and Andrews Counties' AgriLife Extension Offices. The three GCDs replied to our requests but let us know that they do not retain any records of oil/gas water use within their respective districts. The two county offices contacted did not reply with any information.

See Appendix A of LBG-Guyton (2010) for a more detailed summary table and scanned copies of responses received from the GCDs that were sent information.

- The Barton Springs/Edwards Aquifer Conservation District reported one limestone mining operation not listed, as well as one mining operation listed as an active quarry that is no longer in use.
- Bee County and Live Oak GCDs reported that they are unaware of any uranium mines that are using any water because the uranium mines have been closed, are still in reclamation phase, and should not use much or any water. It is conservatively reported that 201 ac-ft of groundwater is used for uranium mining between the two districts.
- Harris-Galveston Subsidence District reported back on five known mining operations and their permitted water use: Swiley and Pit Plant (est. use, 100,000 gal/yr), Hockley Mine (est. use, 1 million gal/yr), Densimix (est. use, 0.1 million gal/yr), Megasand Enterprises (est. use, 3,960 gal/yr), and Petroleum Coke Grinding (est. use, 0 gal/yr). See Appendix A f LBG-Guyton (2010) for details on these water users by HGSD.
- Headwaters UWCD provided a table of mine-water users and their information. It is noted in the table that the Wheatcraft pit has a groundwater permit for 62 ac-ft and that Martin Marietta has a groundwater permit for 47 ac-ft. See Appendix A of LBG-Guyton (2010) for details provided on these water users by HUWCD.
- Hickory UWCD seemed to have the largest discrepancy between permitted mine-water use and reported estimates of water use in the 2007 WFT report. In a table including all but two mining operations, permitted water use was reported for McCulloch and Mason Counties. The total water permitted for McCulloch County came to 4,212 ac-ft, and the total permitted in Mason County, 559 ac-ft. These estimates are much larger than the 171 and 6 ac-ft (respectively) reported in the 2007 WFT report.
- Lost Pines GCD reported use of groundwater for lignite mining only. It reported the groundwater use by ALCOA in 2009 to be 4,410 ac-ft.
- McMullen GCD reported that all sand and gravel pits in the district stopped operating and stopped using water 20 years ago. This fact may reduce assumed water use in this district

- Mesa UWCD reported very little water being used for mining currently.
- Neches and Trinity Valleys GCDs reported that the amounts reported by the 2007 WFT report may be excessive because they are ~6% of total current water production in the district.
- Post Oak Savannah GCD reported a 15,000-ac-ft permit for groundwater use by ALCOA that ends in 2038.
- Sutton County UWCD reported no mining operations in Sutton County and that there should be no water used for such operations.
- Red Sands GCD returned only a hand-drawn map showing known mining operations within the district, some of which were not shown on the GIS map that had been sent out.

13 Appendix F: Water-Rights Permit Data and 2008 Water-Rights Reporting Data

The following two tables (Table 76 and Table 77) list data dump from of the TCEQ database concerning surface-water rights.

Table 76. 2008 Water-rights reporting data

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	AKIN	Sabine	0	0	0
2008	ALAMO CONCRETE PRODUCTS LTD	Brazos	165.424	150.205	15.219
2008	ALCOA INC	Brazos	0	0	0
2008	ALCOA INC	Brazos	0	0	0
2008	ALON USA REFINING INC	Colorado	21.3	0	21.3
2008	ASH GROVE TEXAS LP	Trinity	289.3	0	289.3
2008	BASELINE OIL & GAS CORP	Brazos	1000	0	82.61
2008	BELL SAND COMPANY	Neches	4.75	0	0
2008	BLUE SKY OILFIELD SERVICE LLC	Brazos	0	0	0
2008	BLYTHE	Colorado	0	0	0
2008	BOWIE, CITY OF	Trinity	1.3738	0	1.3738
2008	BRAZOS RIVER AUTHORITY	Brazos	5268	0	5268
2008	BRAZOS RIVER AUTHORITY	Brazos	426	0	426
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	13	0	13
2008	BRAZOS WATER STATION	Brazos	29.09	0	29.09
2008	BRECKENRIDGE GASOLINE CO	Brazos	0	0	0
2008	BURLINGTON RESOURCES OIL & GAS CO LP	Brazos	10	0	10
2008	BURLINGTON RESOURCES OIL & GAS CO LP	Brazos	10	0	10
2008	CAMPBELL CONCRETE & MATERIALS LP	Brazos	1135	997	140
2008	CAPITOL AGGREGATES LTD	Brazos	53.61	0	53.61
2008	CAPITOL AGGREGATES LTD	Colorado	0	0	0
2008	CARAWAY	Brazos	0	0	0
2008	CAVERN DISPOSAL INC	Trinity	36	0	36
2008	CERVENKA	Colorado	0	0	0
2008	CHAMBERS-LIBERTY COS ND	Trinity	0	0	0
2008	CHESAPEAKE ENERGY INC	Brazos	0	0	0
2008	CHEVRON PHILLIPS CHEMICAL CO LP	Brazos-Colorado	453.71	339.71	0

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	CITATION 1994 INVESTMENT LTD PARTNERSHIP	Brazos	0	0	0
2008	CITATION 1998 INVESTMENT LTD PARTNERSHIP	Brazos	0	0	0
2008	CITATION 1998 INVESTMENT LTD PARTNERSHIP	Brazos	58.4567	0	58.4567
2008	CLEBURNE, CITY OF	Brazos	0	0	0
2008	COLORADO RIVER MWD	Colorado	9	0	0
2008	COLORADO RIVER MWD	Colorado	843.2	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	CONOCOPHILLIPS CO	Brazos-Colorado	0	0	0
2008	DALLAS, CITY OF	Trinity	0	0	0
2008	DEVON ENERGY PRODUCTION CO LP	Brazos	0	0	0
2008	EASTLAND INDUSTRIAL FOUNDATION	Brazos	0	0	0
2008	EBAA IRON INC	Brazos	0	0	0
2008	EL PASO CO WID 1	Rio Grande	0	0	0
2008	ENCANA OIL & GAS USA INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	FAIR OIL LC	Cypress	0	0	0
2008	FRANKLIN LIMESTONE COMPANY	Brazos	0	0	0
2008	GEOCHEMICAL SURVEYS	Brazos	0	0	0
2008	GRAHAM, CITY OF	Brazos	0	0	0
2008	GREEN	Canadian	0	0	0
2008	GREENBELT M&I WA	Red	0	0	0
2008	GULF COAST WATER AUTHORITY	Brazos	0	0	0
2008	H R STASNEY & SONS LTD	Brazos	54.51	0	0
2008	HALLWOOD PETROLEUM	Brazos	0	0	0
2008	HANSON AGGREGATES CENTRAL INC	Trinity	2392.24	2221.34	2392.24
2008	HANSON AGGREGATES CENTRAL INC	Trinity	0	0	0
2008	HANSON AGGREGATES WEST INC	Trinity	0	0	0
2008	HANSON AGGREGATES WEST INC	Trinity	125.75	114.44	125.75
2008	HENRIETTA, CITY OF	Red	0	0	0
2008	HUDSPETH COUNTY CRD 1	Rio Grande	0	0	0
2008	INGRAM ENTERPRISES LP	Brazos	43.85	0	43.85

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	J & W SUPPLY INC	Brazos	30	0	30
2008	JACKSON SAND & GRAVEL INC	Trinity	0	0	0
2008	JANES GRAVEL CO	Brazos	446.23	0	0
2008	KEECHI VALLEY CATTLE CO	Brazos	0	0	0
2008	KERSH	Neches	4.75	0	0
2008	LATTIMORE MATERIALS COMPANY	Brazos	63.53	0	63.53
2008	LATTIMORE MATERIALS COMPANY	Brazos	572.14	0	572.14
2008	LEONARD WITTIG GRASS FARMS INC	Brazos-Colorado	0	0	0
2008	LOWER COLORADO RIVER AUTHORITY	Colorado	0	0	0
2008	LOWER COLORADO RIVER AUTHORITY	Colorado	0	0	0
2008	LUMINANT GENERATION CO LLC	Cypress	492	0	492
2008	LUMINANT MINING CO LLC	Sabine	376	0	376
2008	LUMINANT MINING CO LLC	Sabine	0	0	0
2008	MARTIN MARIETTA MATERIALS SOUTHWEST INC	Trinity	0.25	0	0.25
2008	MINERAL WELLS SAND & GRAVEL	Brazos	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOHR	Colorado	0	0	0
2008	MORTON SALT COMPANY INC	Sabine	76.34	0	0
2008	NORTH CENTRAL TEXAS MWA	Brazos	0	0	0
2008	NORTH RIDGE CORPORATION	Brazos	0	0	0
2008	NORTH TEXAS LIVING WATER RESOURCES LLC	Brazos	0	0	0
2008	NORTH TEXAS LIVING WATER RESOURCES LLC	Brazos	0	0	0
2008	OCCIDENTAL PERMIAN LTD	Brazos	0	0	0
2008	PITCOCK BROTHERS READY-MIX	Brazos	0	0	0
2008	PLAINS PETROLEUM OPERATING CO	Brazos	0	0	0
2008	PREMCOR PIPELINE CO	Neches-Trinity	51.468	0	51.468
2008	PUMPCO INC	Brazos	2.7496	0.4677	2.7496
2008	QUICKSILVER RESOURCES INC	Brazos	1709.11	0	1709.11
2008	RED RIVER AUTHORITY	Red	0	0	0
2008	SABINE MINING COMPANY	Sabine	157.76	0	0
2008	SABINE MINING COMPANY	Sabine	0	0	0
2008	SAN JACINTO RIVER AUTHORITY	San Jacinto	0	0	0
2008	SAN JACINTO RIVER AUTHORITY	Trinity	0	0	0
2008	SANCO MATERIALS CO	Colorado	25.6	0	25.6

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	SANCO MATERIALS CO	Colorado	8.76	0	8.76
2008	SCHKADE	Brazos	0	0	0
2008	SHUMAKER ENTERPRISES INC	Colorado	249.74	0	249.74
2008	SOUTHWESTERN GRAPHITE CO	Colorado	0	0	0
2008	SWANSON MULESHOE RANCH LTD	Brazos	0	0	0
2008	SWEPI LP	Brazos	0	0	0
2008	TARRANT INVESTMENT CO INC	Brazos	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	316	0	316
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TAYLOR	Colorado	0	0	0
2008	TERRY JACKSON INC	Colorado	0	0	0
2008	TERRY JACKSON INC	Colorado	0	0	0
2008	TEX IRON INC	Neches	0	0	0
2008	TEXAS INDUSTRIES INC	Trinity	0	0	0
2008	TEXAS INDUSTRIES INC	Colorado	0	0	0
2008	TEXAS MUNICIPAL POWER AGENCY	Brazos	0	0	0
2008	TEXAS MUNICIPAL POWER AGENCY	Brazos	0	0	0
2008	THISTLE DEW RANCH	Brazos	0	0	0
2008	TLC INVESTMENTS LLC	Brazos	0	0	0
2008	TRINITY MATERIALS INC	Brazos	0	0	0
2008	TRINITY MATERIALS INC	Trinity	0	0	0
2008	TRINITY MATERIALS INC	Trinity	51.9814	0	0
2008	TXI OPERATIONS LP	Brazos	0	0	0
2008	TXU BIG BROWN MINING CO LP	Trinity	0	0	0
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Sabine	307	0	307
2008	TXU MINING COMPANY LP	Brazos	0	0	0
2008	TXU MINING COMPANY LP	Cypress	0	0	0
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Cypress	0	0	0
2008	TXU MINING COMPANY LP	Sulphur	65	0	65
2008	TXU MINING COMPANY LP	Cypress	132	0	132
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Sulphur	0	0	0
2008	UNDERWOOD	Brazos	15.81	0	15.81

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	UNION OIL COMPANY OF CALIF	Neches	0	0	0
2008	UNITED STATES DEPT OF ENERGY	Neches-Trinity	50.69	0	50.69
2008	UNITED STATES OF AMERICA	Rio Grande	0	0	0
2008	UPPER NECHES RIVER MWD	Neches	0	0	0
2008	US DEPARTMENT OF ENERGY	Brazos	81.06	0	81.06
2008	VULCAN CONSTRUCTION MATERIALS LLP	Brazos	139.34	0	0
2008	W F COMPANY LTD	Colorado	0	0	0
2008	WAGGONER	Red	0	0	0
2008	WALNUT CREEK MINING COMPANY	Brazos	0	0	0
2008	WEATHERFORD, CITY OF	Trinity	0	0	0
2008	WEIRICH BROTHERS INC	Colorado	0	0	0
2008	WEIRICH BROTHERS INC	Colorado	0	0	0
2008	WEST CENTRAL TEXAS MWD	Brazos	45.91	0	0
2008	WESTERN COMPANY OF TEXAS INC	Brazos	1031.33	0	1031.33
2008	WHARTON COUNTY GENERATION LLC	Brazos-Colorado	0	0	0
2008	WHITE RIVER MWD	Brazos	7.75	0	7.75
2008	WHITE RIVER MWD	Brazos	0	0	0
2008	WHITESIDE	Red	0	0	0
2008	WICHITA CO WID 2	Red	22	0	22
2008	WILLIAMS PRODUCTION GULF COAST LLP INC	Brazos	0.346	0	0
2008	ZEBRA INVESTMENTS INC	Brazos	53.4	0	53.4
	Totals		**564,147.36**	**259,933.12**	**168,660.45**

Source: TCEQ Central Registry database

Table 77. Water-rights permit data

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
UPPER NECHES RIVER MWD		Anderson			AM 10/14/92,9/28/99,3/1/00.MULTI-EVERYTH
SAN MIGUEL ELECTRIC COOP INC	SAN MIGUEL LIGNITE MINE	Atascosa	120.00		SEDIMENTATION CONTROL AND DUST SUPPRESSION PURPOSES
NORTH CENTRAL TEXAS MWA		Baylor	500.00		
BRAZOS RIVER AUTHORITY		Bell			MAX RATE "UNSPECIFIED"
BRAZOS RIVER AUTHORITY		Bell			
FRANKLIN LIMESTONE COMPANY		Bell	138.00	69.00	
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	431.00	5.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	769.00	10.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	3,304.00	585.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
JOHN MCPHERSON ET AL		Bosque			AMENDED 5/15/2009: CHANGE TO MULTI-USE; ADDED MINING USE
CHEVRON PHILLIPS CHEMICAL CO LP	CLEMENS TERMINAL	Brazoria	3,000.00		
CHEVRON PHILLIPS CHEMICAL CO LP	CLEMENS TERMINAL	Brazoria	2,350.00		
UNITED STATES DEPT OF ENERGY	BRYAN MOUND SPR SITE NEAR FREEPORT	Brazoria	52,000.00		TOTAL 215K. AM 7/31/89, 3/26/2001
APACHE CORPORATION		Brazos	20.00		
LOWER COLORADO RIVER AUTHORITY		Burnet			SEE 5482-6.AM 10/89,3/90,3/96.AM C ABAND
SOUTHWESTERN GRAPHITE CO	DIV OF DIXON TICONDEROGA	Burnet	400.00		
GUADALUPE-BLANCO RIVER AUTHORITY		Calhoun			AM 4/91,5/04,9/04,5/1/2007:STAT DISTRICT
UNION CARBIDE CHEM & PLASTICS		Calhoun			AMEND 4/17/91.PART OWNER WITH GBRA
DOUGLAS M BRICE		Cameron			AMEND 3/13/95, 6/4/99
JOEL RUIZ ET UX		Cameron			RATE:23-2707.AMEND 10/30/84,7/2/99

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
MICHAEL A MACMAHON		Cameron	9.62		AMEND 6/6/97:DIVPTS 8 COS BELOW AMISTAD
PABLO A RAMIREZ INC		Cameron			" " .5 COUNTIES."
TXU MINING COMPANY LP	MONTICELLO-LEESBURG LIGNITE MINING AREA	Camp	685.00		SCs.DUST SUPPR,CNSTR,EQUIP.AM A:CORR DPs
CHAMBERS-LIBERTY COS ND		Chambers			AMEND 10/25/04:ADD USES & IBT TO 80000AF
CHAMBERS-LIBERTY COS ND		Chambers	800.00		
CITY OF HENRIETTA		Clay	1.00		
COLORADO RIVER MWD		Coke	8,427.00		MAY DIVERT 6000 AF IN CO 168. "
COLORADO RIVER MWD		Coke	1,000.00		MAY DIVERT 6000 AF IN CO 168. "
PATTY LOIS CERVENKA		Coke	100.00		& CO 200.AMEND 5/10/2007:ADD MINING USE
RAMONA A TAYLOR		Coke	40.00		& IRRIGATION. 3 DIVPTS. AMEND 11/12/99
SANCO MATERIALS CO		Coke	35.00		DIVERT 309 AF.AMEND 10/96,10/98.3 DIVPTS
SANCO MATERIALS CO		Coke	32.00		DIVERT 320 AF.SC.AM 10/98,9/99.2 DIVPTS
BRAZOS RIVER AUTHORITY		Comanche			
R E JANES GRAVEL CO		Crosby	450.00		
WHITE RIVER MWD		Crosby	2,000.00		
CITY OF DALLAS		Dallas			AM 84,85,86,1/96,3/1/96,6/02,11/04,10/06
H S JACKSON SAND & GRAVEL INC		Denton	3.00		8/07 MAIL RETD: RTS/BOX CLOSED/UTF
CHARLES LYDELL THALMANN		Dimmit	1.00		AMEND 2/26/90
GREENBELT M&I WA		Donley	750.00		
EASTLAND INDUSTRIAL FOUNDATION		Eastland	607.00		
EBAA IRON INC		Eastland	1,000.00		
EL PASO CO WID 1	MESILLA, AMERICAN, RIVERSIDE DIV DAMS	El Paso			ADJUDICATED FROM 5433-1
HUDSPETH COUNTY CRD 1		El Paso			& HUDSPETH CO. ADJUDICATED FROM 244/236-1 IN 2007
UNITED STATES OF AMERICA	MESILLA, AMERICAN, RIVERSIDE DIV DAMS	El Paso			ADJUDICATED FROM 5433-1
ASH GROVE TEXAS LP		Ellis	82.00	50.00	AMENDED 1/5/2001: INCREASE DIV RATE
TARRANT INVESTMENT CO INC		Erath	30.00		USE 1 UNDER ADJ 4026. "; 7/09 MAIL RTD;RTS/ANK/UTF
CAMPBELL CONCRETE & MATERIALS LP		Fort Bend	2,300.00	230.00	AMEND 4/12/2000:ADD DIVPT,IMPOUNDMENT

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
GULF COAST WATER AUTHORITY		Fort Bend			WHICH PRIORITY DATE?
CAVERN DISPOSAL INC		Freestone	31.00		129 AF USE 4 EXPIRED 12/92
TARRANT REGIONAL WATER DIST		Freestone			ALSO CO 175. AMEND 1/4/2000, 2/8/2005
TARRANT REGIONAL WATER DIST	DISTRICT RETURN FLOWS	Freestone			AMEND 2/8/05:DISTRICT RETURN FLOWS.2 DPs
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone	5.00		SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
CITATION 2002 INVESTMENT LP		Garza	200.00		AMEND 8/93; WITH WSC 2418
WHITE RIVER MWD		Garza	4,000.00		8/4/2005: CONSTR EXTENDED TO 7/24/2012. 1/21/2009: CONSTR EXTENDED TO 7/24/2016
WAYNE E MOHR		Gillespie	30.00		AMND 1/24/96:2ND DIV PT:30.272N/98.781W
WEIRICH BROTHERS INC		Gillespie	50.20		WASH GRAVEL. AMEND 8/25/95
RED RIVER AUTHORITY		Grayson	100.00		
G R AKIN ET AL		Gregg	5.20		
TEXAS MUNICIPAL POWER AGENCY	GIBBONS CREEK LIGNITE MINE	Grimes			AMEND 1/24/05:ADD USES 7, 8, 11
TEXAS MUNICIPAL POWER AGENCY	GIBBONS CREEK LIGNITE MINE	Grimes	200.00		AMEND 12/16/04:ADD USES
FAIR OIL LC		Harrison	165.21		& CO 158
SABINE MINING COMPANY	PIRKEY POWER PLANT	Harrison	200.00		
SABINE MINING COMPANY	SOUTH HALLSVILLE #1 SURFACE LIGNITE MINE	Harrison			REDIRECT ALL OF BRANDY BR TO HATLEY CRK
TARRANT REGIONAL WATER DIST		Henderson			AMEND 7/93, 1/4/2000, 2/8/05
TARRANT REGIONAL WATER DIST	DISTRICT RETURN FLOWS	Henderson			AMENDED 2/8/05:ADD DISTRICT RETURN FLOWS
TEX IRON INC		Henderson			STORED GROUNDWATER. CRUSHED STONE WASHING
DOUGLAS M BRICE		Hidalgo			AMEND 3/13/95, 6/4/99

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
HIDALGO CO IRR DIST 2		Hidalgo	100.00		7/14/81,6/10/87,5/15/90,5/8/95,4/13/2000
HIDALGO CO WID 3		Hidalgo	100.00		AMENDED 10/10/78, 9/8/95
HIDALGO COUNTY IRR DIST 16		Hidalgo	200.00		AMEND 8/11/95, 7/12/96
JOEL RUIZ ET UX		Hidalgo			RATE:23-2707.AMEND 10/30/84,7/2/99
LUCIO E GONZALEZ JR		Hidalgo	5.00		
PABLO A RAMIREZ INC		Hidalgo			" " .5 COUNTIES."
RUFINO GARZA ET AL		Hidalgo	125.00		AMENDED 11/1/93, 8/30/94, 1/8/99
SERGIO GALINDO		Hidalgo	100.00		AMENDED 4/25/2007:CHG IRR TO MINING
BRAZOS RIVER AUTHORITY		Hill			
CITY OF CLEBURNE		Hill			
BRAZOS RIVER AUTHORITY		Hood			
BURLINGTON RESOURCES OIL & GAS CO LP		Hood	600.00		AMMENDED 2/6/2009- INCREASED DIVERSION AMT FROM 400 AC-FT TO 600 AC-FT
CARRIZO OIL & GAS INC		Hood	15.00		
CHESAPEAKE ENERGY INC		Hood	2,000.00		
ENCANA OIL & GAS USA INC		Hood	17.00		REPLACED 12179-9
EOG RESOURCES INC		Hood	680.00		
EOG RESOURCES INC EASTERN DIVISION		Hood	300.00		
LOWELL UNDERWOOD		Hood	100.00		
QUICKSILVER RESOURCES INC		Hood	1,400.00		
WESTERN COMPANY OF TEXAS INC		Hood	1,000.00		SYSOP
WILLIAMS PRODUCTION GULF COAST LLP INC		Hood	86.00		
TXU MINING COMPANY LP	MONTICELLO-THERMO LMA	Hopkins	220.00		DUST SUPPR,CONSTR,MISC.4 DPS,3 RES.SCs
ALON USA REFINING INC		Howard	215.00		OIL WELL FLOODING; & USE 2
COLORADO RIVER MWD	BEALS CREEK PROJECT	Howard	2,200.00	2,000.00	& WATER QUALITY IMPROVEMENT
COLORADO RIVER MWD	NATURAL DAM LAKE PROJECT	Howard	2,500.00		&CO 159;& USE 8-WATER QUALITY CTRL; IMP
W F COMPANY LTD		Howard	800.00		NOTIFY CLEANRIVERS OF CHG.MAIL RETD 6/07

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TEXAS INDUSTRIES INC	BOONESVILLE PLANT	Jack			50 AF PURCHASED FROM TARRANT CO WCID 1
PREMCOR PIPELINE CO		Jefferson	76.70		
UNITED STATES DEPT OF ENERGY	BIG HILL SPR SITE	Jefferson	30,000.00		AMND 7/12/90.87291 AF ABANDONED 3/20/96
TRINITY MATERIALS INC	CLEBURNE PLANT	Johnson	125.00		CONSUMPTIVE USE UNDER WSC#2210
GEOCHEMICAL SURVEYS		Jones	40.00		2 LAKES.6/06 MAIL RETD:RTS/ANK/UTF
RICHARD SCHKADE		Jones	5.00		CLEANING AND REUSE IN ROCKSAW COOLING
TLC INVESTMENTS LLC		Jones	338.00		
TRINITY MATERIALS INC	SEAGOVILLE SAND & GRAVEL #280	Kaufman	100.00		WITH WSC 2300. AMEND 12/21/2006: MOVE DIVPT. MAIL RETD 3/09: RTS/NO MAIL RECEPTACLE/UTF
OCCIDENTAL PERMIAN LTD	COGDELL CANYON REEF UNIT	Kent	3,525.00		
OCCIDENTAL PERMIAN LTD	COGDELL CANYON REEF UNIT	Kent	2,375.00		
DARRELL G LOCHTE ET AL		Kerr	143.00		123 AF NONCONSUMPTIVE.9/07 MAIL RETD:RTS
WHEATCRAFT INC		Kerr			AM 8/7/2000:CONTRACT.10/04/2006:MU, DPs
WHEATCRAFT INC		Kerr			AMEND 4/18/2006: ADD MINING (MULTI-USE)
WEIRICH BROTHERS INC	KIMBLE CO PLANT	Kimble	60.00	6.00	
PLAINS PETROLEUM OPERATING CO		Knox	235.00		SECONDARY OIL RECOVERY. W/WSC _____
SAN JACINTO RIVER AUTHORITY		Liberty			MULTI-USES,COUNTY,PRI. AMEND 5/95, 10/3/06
TXU MINING COMPANY LP	KOSSE LIGNITE MINE	Limestone	1,000.00		DUST SUPPRESSION, CONSTRUCTION, & MISC MINING ACTIVITIES
COLORADO RIVER MWD	O H IVIE RESERVOIR	Martin			DIV 2500 AF TOTAL FROM EITHER RESERVOIR FOR INDUSTRIAL OR MINING USE
TERRY JACKSON INC		Mason			1.5 AF CONTRACT WATER. WITH WSC 12254-9
ALAMO CONCRETE PRODUCTS LTD		Maverick	78.00	15.00	AMEND 4/22/87,12/12/94.15 AF CONSUMPTIVE
DE LOS SANTOS READY MIX		Maverick	2.00		AMEND 1/24/91,3/14/01,4/18/01,11/03/03
DOUGLAS M BRICE		Maverick			AMEND 3/13/95, 6/4/99
EW RITCHIE III ET AL		Maverick			
KATHRYN RITCHIE COTTER ET AL		Maverick	10.00		AMEND 7/6/93
MILDRED GOODSON		Maverick			AMEND 3/27/02, SPECIAL COND

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
JIMMY A MUMME ET UX		Medina	15.00		AMENDED 10/20/04:ADD DIV PT,FLOW RESTRIC
MOBLEY COMPANY INC		Menard	3.00		
ALCOA INC	SANDOW MINE RECLAMATION PROJ	Milam			STORE GW IN RESERVOIRS.SEE 5816-1.SCs
ALCOA INC		Milam			STORE GW IN RESERVOIRS.SEE 5803-1.SCs
CITY OF BOWIE		Montague	200.00		
CLARICE BENTON WHITESIDE		Montague	9.00		
SAN JACINTO RIVER AUTHORITY		Montgomery	5,500.00		
CITY OF CORPUS CHRISTI		Nueces	12.00		TRANSBASIN TO BASINS 20, 22.ORDER 4/2001
CITY OF CORPUS CHRISTI	JC ELLIOTT LANDFILL & ADJACENT CITY PROP	Nueces			SC
TOM W GREEN		Oldham	30.00		
3 N1 WATER SOLUTIONS		Palo Pinto	250.00		
3 N1 WATER SOLUTIONS		Palo Pinto	250.00		
BASELINE OIL & GAS CORP		Palo Pinto	1,000.00		REPLACED 2420-9
BLUE SKY OILFIELD SERVICE LLC		PALO PINTO	15.00		
BRAZOS RIVER AUTHORITY		Palo Pinto			
BRAZOS WATER STATION		Palo Pinto	100.00		AMENDMENT CHANGES EXPIRE DATE TO 12/31/2009
BRAZOS WATER STATION		Palo Pinto	50.00		
BURLINGTON RESOURCES OIL & GAS CO LP		Palo Pinto	200.00		AMMENDED 2/6/09- CHANGE DIVERSION AMT FROM 400 AC-FT TO 200 AC-FT
CITATION 1998 INVESTMENT LTD PARTNERSHIP		Palo Pinto	175.00		GOES W/ APP#5359(UPSTREAM CONTRACT)
DART OIL & GAS CORP		Palo Pinto	10.00		
DEVON ENERGY PRODUCTION CO LP		Palo Pinto	100.00		
EOG RESOURCES INC		Palo Pinto	320.00		AMENDMENT ADDS A DIVERSION PT.
EOG RESOURCES INC WESTERN DIVISION		Palo Pinto	190.00		
INGRAM ENTERPRISES LP		Palo Pinto	50.00		
LATTIMORE MATERIALS COMPANY		Palo Pinto	300.00		

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
MINERAL WELLS SAND & GRAVEL INC		Palo Pinto	15.00		
NORTH RIDGE CORPORATION		Palo Pinto	235.00		
NORTH TEXAS LIVING WATER RESOURCES LLC		Palo Pinto	2,700.00		MULTIUSE=MINING & IRRIGATION
NORTH TEXAS LIVING WATER RESOURCES LLC		Palo Pinto	650.00		MULTIUSE=MINING & IRRIGATION
PIONEER NATURAL RESOURCES USA INC		Palo Pinto	129.00		REPLACED 12062-9
R J CARAWAY		Palo Pinto	41.00		
RANGE RESOURCES CORPORATION		PALO PINTO	90.00		
THISTLE DEW RANCH		Palo Pinto			
VULCAN CONSTRUCTION MATERIALS LLP		Palo Pinto	2,000.00		REPLACED 1315-9
LUMINANT MINING CO LLC	MARTIN LAKE LMA	Panola	250.00		3 RES, 3 DIV PTS. ALSO RUSK CO. MINING, D&L, SEDIMENT CONTROL. AMENDED 5/11/2009: COMBINE 5004 INTO 5889
TXU MINING COMPANY LP	MARTIN LAKE LIGNITE MINING AREA	Panola	600.00		21 DIV PTS.SCs.EXEMPT RES.AMN 3/30/07
TXU MINING COMPANY LP	MARTIN LAKE LIGNITE MINING AREA	Panola	400.00		AMEND 3/30/07:ADD 400AF,RESES,USES
TXU MINING COMPANY LP		Panola	150.00		11 DIV PTS. SCs
XTO ENERGY INC		Panola	720.00		
CITY OF WEATHERFORD		Parker			AMEND 9/8/04
TXI OPERATIONS LP	TIN TOP	Parker			
APACHE CORPORATION		Robertson	20.00		
BRAZOS RIVER AUTHORITY		Robertson			
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson	685.00	53.00	TOTAL OF 12 DIVPTS.SCs. GW FROM DEWATER
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs
WALNUT CREEK MINING COMPANY		Robertson			LIGNITE MINE SEDIMENTATION POND
BONNIE JO BLYTHE ET AL		Runnels	70.00		2 TRACTS 531.4 ACRES, SC. "
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk	680.00		SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk	680.00		DP1. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP2.DUST SUPPR,CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP3. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP4. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP5. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP6. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP7. DUST SUPPR, CONSTR, EQUIP WASH,MISC
MOBLEY COMPANY INC		Schleicher	3.00		
COLORADO RIVER MWD		Scurry			&CO 17.AMEND 9/26/2001:DIV PTS, ADD IRR
H R STASNEY & SONS LTD		Shackelford			AMEND 5/13/2009: CHANGE TO MULTI-USE: LIVESTOCK, DOMESTIC, & MINING PURPOSES
BELL SAND COMPANY		Smith	60.00	6.00	SAND WASHING

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
R E KERSH		Smith	57.00	6.00	SAND AND GRAVEL WASHING
CLEMMACO LTD		Starr			AMEND 9/19/97, 7/30/2008: COMBINATIONS
DOUGLAS M BRICE		Starr			AMEND 3/13/95, 6/4/99
JOEL RUIZ ET UX		Starr			RATE:23-2707.AMEND 10/30/84,7/2/99
PABLO A RAMIREZ INC		Starr	30.00		" " .5 COUNTIES."
ROSITA GRAVEL INC		Starr	22.50		AMENDED 11/14/97: CHANGE USE 3 TO USE 4
BRECKENRIDGE GASOLINE CO		Stephens			6/06 MAIL RETD:RTS/NDAA/UTF
SWANSON MULESHOE RANCH LTD		Stephens	218.00		AMEND 8/12/86: REVERTS TO REC USE
WEST CENTRAL TEXAS MWD		Stephens			AMEND 3/6/91,10/11/2002
CITATION 1994 INVEST LTD PART		Stonewall	235.00		WITH CONTRACT #1995 (? CONTRACT EXPIRED)
MOBLEY COMPANY INC		Sutton	3.00		
TARRANT REGIONAL WATER DIST	TO FT WORTH HOLLY WWTP	Tarrant			B&B CONVEYANCE OF PIPELINE WATER. MAX RATE NOT TO EXCEED DISCHARGED RATE
TARRANT REGIONAL WATER DISTRICT		Tarrant			AMEND 5/14/85, 1/4/2000, 2/21/2005. MAX RATE UNSPECIFIED
LUMINANT GENERATION CO LLC	MONTICELLO STEAM ELECTRIC STATION	Titus			DUST SUPPRESSION,EQUIP WASHDOWN & MISC
TXU MINING COMPANY LP	MONTICELLO LIGNITE MINING AREA	Titus	50.00		SCs. 13 DIVPTS, 7 RESERVOIRS
TXU MINING COMPANY LP	MONTICELLO LMA	Titus	135.00		6 DPS, 2 RES. SCs.
TXU MINING COMPANY LP	MONTICELLO LIGNITE MINING AREA	Titus	200.00		3 DIV SEGMENTS & 5 RES. SCs
UPPER COLORADO RIVER AUTH		Tom Green			AMENDED 12/19/97, 5/30/2008, 6/13/2008
CAPITOL AGGREGATES LTD	AUSTIN SAND-GRAVEL PLANT READY MIX	Travis	2,540.00	340.00	AMENDED 8/15/97: COMBINED WITH 5378-6; PERMIT EXPIRES UPON PERMANENT CESSATION OF MINING OPS
CAPITOL AGGREGATES LTD	AUSTIN SAND-GRAVEL PLANT READY MIX	Travis	242.00	0.00	AMENDED 8/15/97: COMBINED WITH 5378-6. THIS IS NONCONSUMPTIVE MINING USE
LOWER COLORADO RIVER AUTHORITY		Travis			SEE 5478.AMEND 10/12/89,3/8/90,10/31/91
SHUMAKER ENTERPRISES INC		Travis	300.00		REPLACED 2208-9;AMENDED 11/01
TERRY JACKSON INC		Travis	1.50		1.5 AF CONTRACT WATER. SEE PERMIT 12244-1

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TEXAS INDUSTRIES INC	GREEN SAND AND GRAVEL PLANT	Travis	110.00	11.00	690 A/F EXP 12/31/93; ALL WATER RIGHTS EXPIRE WHEN MINING ENDS OR UPON EXPIRATION OF LEASE; FLOW RESTR ON EXPIRED WATER
TYLER SAND COMPANY		Upshur	200.00		1/99: SEE SC A, CO DEFUNCT; WUR/NOT N
CAPITOL AGGREGATES INC	DEL RIO PLANT	Val Verde	166.00	17.00	AM 11/2/87.6/28/2001:ADD DIVPT & PLACE
MORTON SALT COMPANY INC		Van Zandt	251.00		EXEMPT LAKE
UNION OIL CO OF CALIFORNIA		Van Zandt	400.00		
UNION OIL CO OF CALIFORNIA		Van Zandt	270.00		
UNION OIL CO OF CALIFORNIA		Van Zandt	500.00		
BRAZOS RIVER AUTHORITY		Washington			
ALBERT F MULLER JR		Webb	2.38		
ALICE SOUTHERN EQUIP SERVICE		Webb	145.00		AMEND 7 & 11/93,12/94,10/30/98
ALICE SOUTHERN EQUIP SERVICE		Webb	175.00		AMENDED 10/30/98
BARBARA T FASKEN	FARCO MINE DAM AREA	Webb	200.00		
BEN-HUR ENTERPRISES LTD		Webb			AMEND 1/24/91,3/14/2001,4/18/2001.2705-6
CHRISTINE MCKEE		Webb	1.00		AMEND 6/20/87. USE 4 IN ZAPATA & WEBB
CITY READY MIX INC		Webb	100.00		AMEND 10/15/91, 11/23/92
DOUGLAS M BRICE		Webb	131.56		AMEND 3/13/95, 6/4/99
H B O'KEEFE ESTATE		Webb	100.00		AMENDED 8/14/98: 100 AF USE 3 TO USE 4
HACHAR REAL ESTATE COMPANY		Webb	23.00		AMEND 6/30/86
J & B CONTRACTORS INC		Webb	2.00		AMEND 3/29/94
JOEL RUIZ ET UX		Webb			RATE:23-2707.AMEND 10/30/84,7/2/99
LAREDO SAND & GRAVEL CO		Webb	20.00		
LOUIS C LECHENGER ET AL		Webb	20.00		AMEND 4/14/88
MANDEL PROPERTIES LTD		Webb	100.00		AMEND 10/13/95
MICHAEL ALLEN MACMAHON		Webb	120.00		6/18/90
RANCHO BLANCO CORPORATION		Webb	300.00		AMEND 11/2/87,9/25/89,10/11/94,8/25/95
RODOLFO GARCIA		Webb	75.00	10.00	
RODOLFO GARCIA		Webb	62.00		
SAMUEL A MEYER ET AL		Webb	30.00		AMEND 10/17/94
SAN ISIDRO NORTH LTD		Webb			AMEND 12/18/91, 5/31/96. AMEND 3/19/2008: ADD MINING USE. AMEND 7/2/2008: ADD INDUSTRIAL USE

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
STEPHEN A MCKENDRICK TRUSTEE		Webb	2.38		W H MCKENDRICK TRUST
TOPAZ POWER PROPERTY MGMT II LP		Webb			AMEND 2/7/97.REUSE 731.5 OF THE 2194.5
UNION PACIFIC OIL & GAS CO		Webb	5.00		AMEND 6/16/92
WILLIAM H MCKENDRICK III		Webb	8.33		
CONOCOPHILLIPS CO		Wharton			
LEONARD WITTIG GRASS FARMS INC		Wharton	1,000.00		
WHARTON COUNTY GENERATION LLC	NEWGULF POWER FACILITY	Wharton			
WICHITA CO WID 2 ET AL		Wichita	2,000.00		
W T WAGGONER ESTATE		Wilbarger	30.00		FROM MIDWAY LAKE
JOEL RUIZ ET UX		Willacy			RATE:23-2707.AMEND 10/30/84,7/2/99
PABLO A RAMIREZ INC		Willacy			" " .5 COUNTIES."
ALAMO CONCRETE PRODUCTS LTD	WEIR PLANT	Williamson	300.00	30.00	AM 6/92,5/02.FORMERLY SOUTHWEST MATERIAL
BRAZOS RIVER AUTHORITY		Williamson			
BRAZOS RIVER AUTHORITY		Williamson			
CAPITOL AGGREGATES LTD	GEORGETOWN QUARRY	Williamson	118.00		AMENDED 8/15/97, 5/28/99: ADDED DIV PT
GENE H BINGHAM ET AL		Williamson	240.00	24.00	MAY CONSUMPTIVELY USE 24AFY
HANSON AGGREGATES CENTRAL INC	BRIDGEPORT STONE PLANT #2	Wise	345.00	69.00	
HANSON AGGREGATES CENTRAL INC	BRIDGEPORT STONE PLANT #2	Wise	1,505.00	301.00	
HANSON AGGREGATES CENTRAL INC	CHICO CRUSHED STONE PLANT	Wise	510.00		AMEND 5/7/91
HANSON AGGREGATES WEST INC		Wise	1,475.00		
HANSON AGGREGATES WEST INC		Wise	177.00	177.00	
MARTIN MARIETTA MATERIALS SOUTHWEST INC		Wise	1,200.00		
TARRANT REGIONAL WATER DIST		Wise	7,500.00		COS 249, 220
TARRANT REGIONAL WATER DIST		Wise			AMEND 5/5/89,1/4/2000. COS 249,119

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TRINITY MATERIALS INC	DECATUR PLANT #205	Wise	25.00		SC. W/WSC#1970
CITY OF GRAHAM		Young	500.00		
PITCOCK BROTHERS READY-MIX		Young	100.00		
ANTONIO R SANCHEZ SR ESTATE		Zapata	50.00		3/87,8/87,9/88,7/89,5/10/2000.9 COUNTIES
ANTONIO R SANCHEZ SR ESTATE		Zapata	50.43		3/87,8/87,9/88,7/89,5/10/2000.9 COUNTIES
DOUGLAS M BRICE		Zapata			AMEND 3/13/95, 6/4/99
EDWIN H FRANK III		Zapata	6.00		AMEND 1/4/90
EL CAMPO FARM COMPANY		Zapata	25.00		SEE 23-2787 FOR RATE
FENDER EXPLORATION & PRODUCTION CO LLC		Zapata	20.00		AMEND 10/25/2000:CHG 20 AF TO MINING USE
FLF LTD		Zapata	7.46		AMEND 1/4/90
GALBERRY PROPERTIES LLC		Zapata	5.60		AMEND 1/4/90
HERRADURA RANCH		Zapata	6.30		AMEND 1/4/90
JAMES C GUERRA ET AL		Zapata	12.50		AMEND 8/14/98: CHG POFD & USE 3 TO 4
JAVIER ZAPATA ET AL		Zapata	146.00		
JOEL RUIZ ET UX		Zapata	20.00		RATE:23-2707.AMEND 10/30/84,7/2/99
KCS RESOURCES INC		Zapata	25.00		
LARRY G HANCOCK		Zapata	6.10		AMEND 1/4/90
LONE STAR LA PERLA LP		Zapata	5.64		AMEND 1/4/90
MARIA EVA URIBE RAMIREZ		Zapata	10.00		AMEND 7/12/90
MARTINEZ QUARTER HORSE RANCH LTD		Zapata			AM 5/3/06:ADD MINING.6/13/07:ADD ACRES
MARTINEZ QUARTER HORSE RANCH LTD		Zapata	2.80		AMEND 1/4/90
MICHAEL T THRASHER		Zapata	6.10		AMEND 1/4/90
NEUHAUS & CO LTD		Zapata	17.10		AMEND 1/4/90
PABLO A RAMIREZ INC		Zapata			" " .5 COUNTIES."
RAMIRO V MARTINEZ		Zapata			AMEND 3/16/05:ADD IND & MINING USES
ROBERTO J VIDAURRI		Zapata			AM 5/92,6/93,08/02,9/26/02,7/31/2009:MULTI-USE,DIV
ROSEMARIE ANN GEARY		Zapata			AM 12/1/86,4/12/94,7/27/01,11/4/03:MULTI
SDK FARMS		Zapata	12.90		AMEND 1/4/90
SDK FARMS LLC		Zapata			AM 5/3/06:ADD MINING.6/13/07:ADD ACRES

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TECOMATE CAPITAL PARTNERS LTD		Zapata	4.00		AMEND 1/4/90
UNICO CONSTRUCTION CO		Zapata	11.24		AMEND 5/31/85,3/13/2003:CHG USE TO 4/AG
WICHITA PARTNERSHIP LTD		Zapata			AM 1/30/95.6/21/2007:MULTIUSE.3/13/08:CM
ZAVALA-DIMMIT CO WID 1		Zavala	4.00		
ZAVALA-DIMMIT CO WID 1		Zavala			
ZAVALA-DIMMIT CO WID 1		Zavala			
CITY OF HOUSTON					

Source: TCEQ Central Registry database

14 Appendix G:
vvvvv

15 Appendix H:

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16 Appendix I: yyyyy

17 Appendix J:
List of Files Submitted to TWDB and Content

17.1 List of Files with Nonproprietary Content

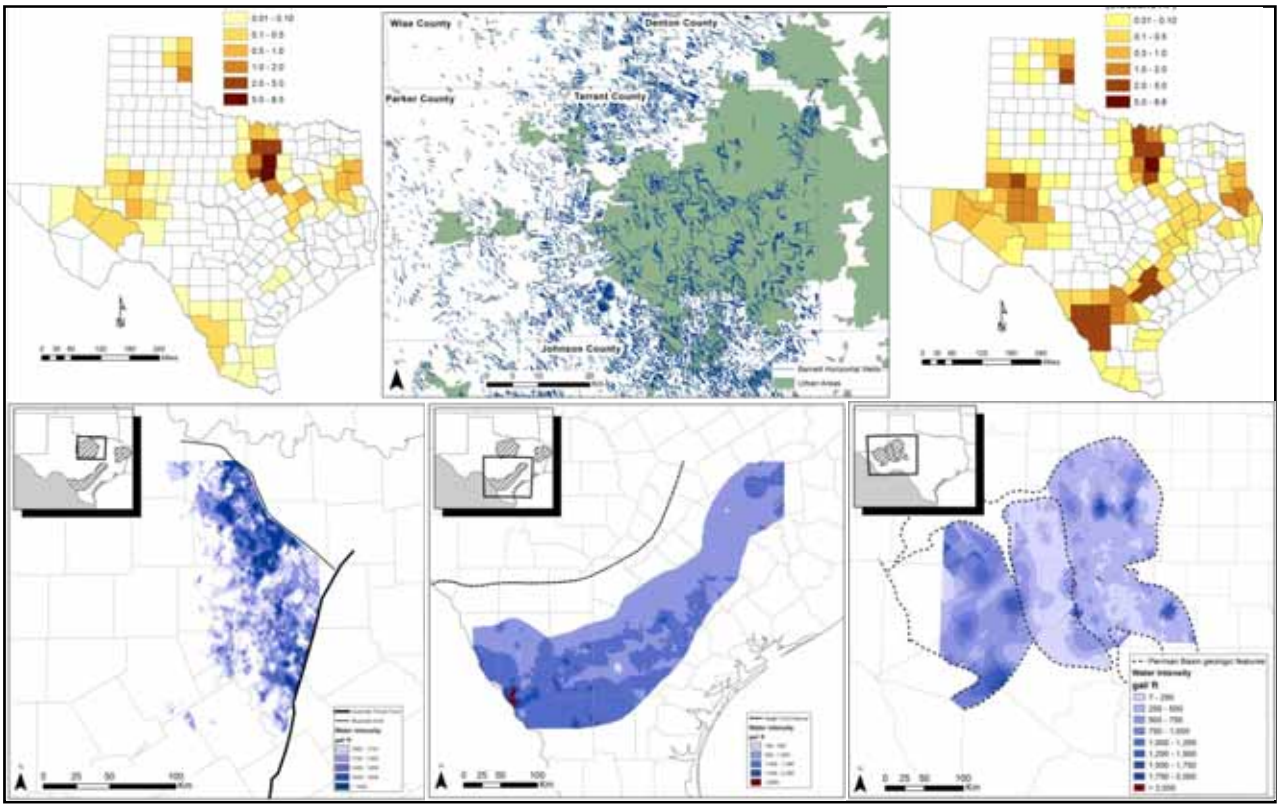
17.2 List of Files with Proprietary Content

18 Appendix K:
Responses to Review Comments

Responses to Review Comments
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September 2012

Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report

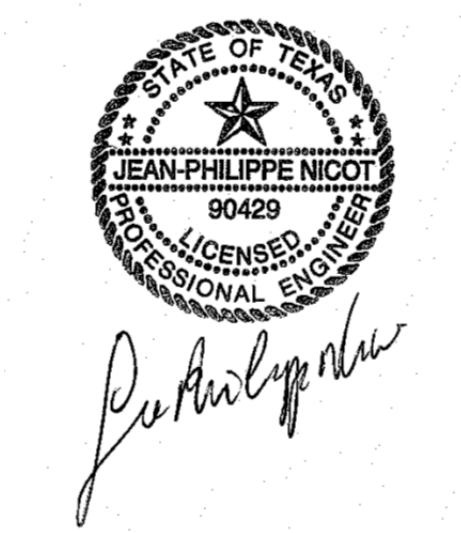


Prepared for
Texas Oil & Gas Association, Austin, Texas

Bureau of Economic Geology
Scott W. Tinker, Director
Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas 78713-8924

Oil & Gas Water Use in Texas:
Update to the 2011 Mining Water Use Report

Jean-Philippe Nicot, P.E., P.G., Robert C. Reedy, P.G.,
Ruth A. Costley, and Yun Huang, P.E.



Bureau of Economic Geology
Scott W. Tinker, Director
Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas 78713-8924

Executive Summary

In Spring 2012, we undertook an update of the hydraulic fracturing sections of the TWDB-sponsored report titled "Current and Projected Water Use in the Texas Mining and Oil and Gas Industry" that we published in June 2011 (Nicot et al., 2011). The 2011 report provided estimated county-level water use in the oil and gas industry in 2008 and projections to 2060. This 2012 update was prompted by two main events: (1) a major shift of the oil and gas industry from gas to oil production, displacing production centers across the state and impacting county-level amounts; (2) rapid development of technological advances, resulting in more common reuse and in the ability to use more brackish water. The timely update was enabled by a faster than anticipated development, translating into abundant statistical data sets from which to derive projections, and by an increased willingness of the industry to participate in providing detailed information about water use in its operations. This document follows the same methodology as the 2011 report but differs from it in two ways. Our current update clearly distinguishes between water use and water consumption. The 2011 report does not include reuse from neighboring hydraulic fracturing jobs, recycling from other industry operations or other treatment plants, and use of brackish water. Our update also presents three scenarios: high, low, and most likely water use and consumption with a focus on water consumption. This update has been reviewed by the TWDB and should supersede oil and gas industry projections from the 2011 report.

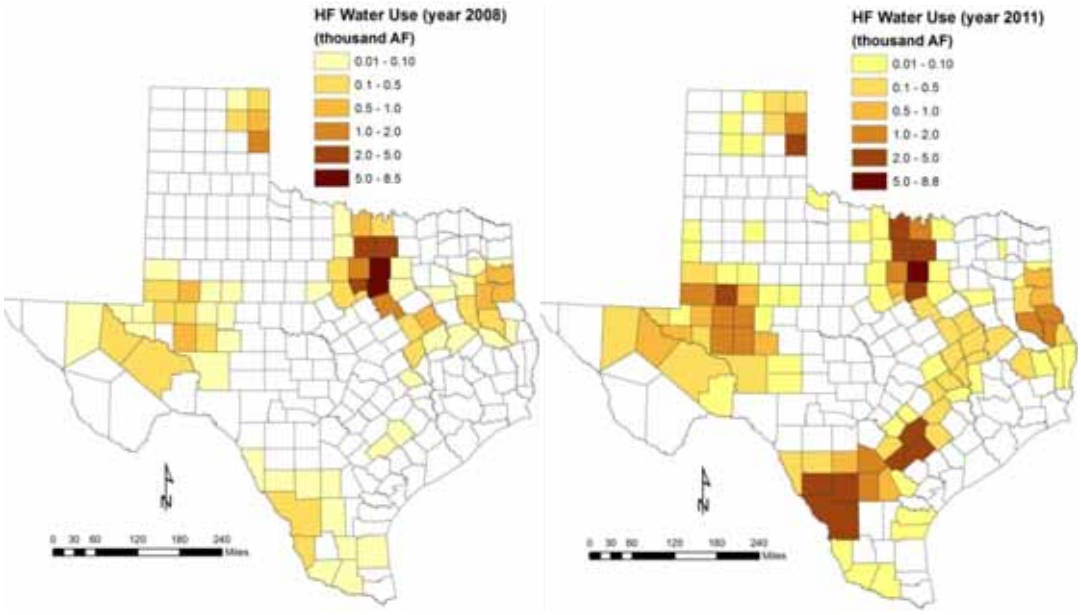


Figure ES1. Spatial distribution of hydraulic fracturing water use in 2008 (~36,000 AF) and 2011 (~81,500 AF).

Overall we find that, if the total water use for hydraulic fracturing has increased from 36,000 AF in 2008 to ~81,500 AF in 2011 (Figure ES1), the amount of recycling/reuse and the use of brackish water have also increased (~17,000 AF in 2011, or 21%). Hydraulic fracturing has expanded to the southern and western, drier parts of the state and, by necessity, the industry has had to adapt to those new conditions. Collected information tends to suggest that the industry has

been decreasing its fresh-water consumption despite the increase in water use. Total water use information is relatively easy to access (through the private database vendor IHS), but true consumption is harder to gauge.

The updated hydraulic fracturing projections at the state level do not show a major departure from and are essentially consistent with the previous report but have a more subdued peak and a longer tail (Figure ES2). This is due to the increased likelihood that the industry has hydraulically fractured more formations that can be placed into the tight oil and gas category. The annual peak water use previously estimated at 145,000 AF in the early 2020's is now thought to be a broad peak plateauing at ~125,000 AF/yr during the 2020's. However, fresh water consumption is estimated to stay at the general level of ~70,000 AF/yr and to decrease in future decades. Adding other oil and gas industry water uses, such as waterflooding and drilling, brings projected maximum water use up to ~180,000 AF/yr during the 2020-2030 decade with a much lower consumption which brings the total mining water use to a maximum of ~340,000 AF/yr around the year 2030. These values remain small compared to the state water use (Figure ES3). In 2010, hydraulic fracturing water use represented about 0.5% of the water use in the state. However, the hydraulic fracturing water use is unevenly distributed across the state and may represent locally a higher fraction of the total water use.

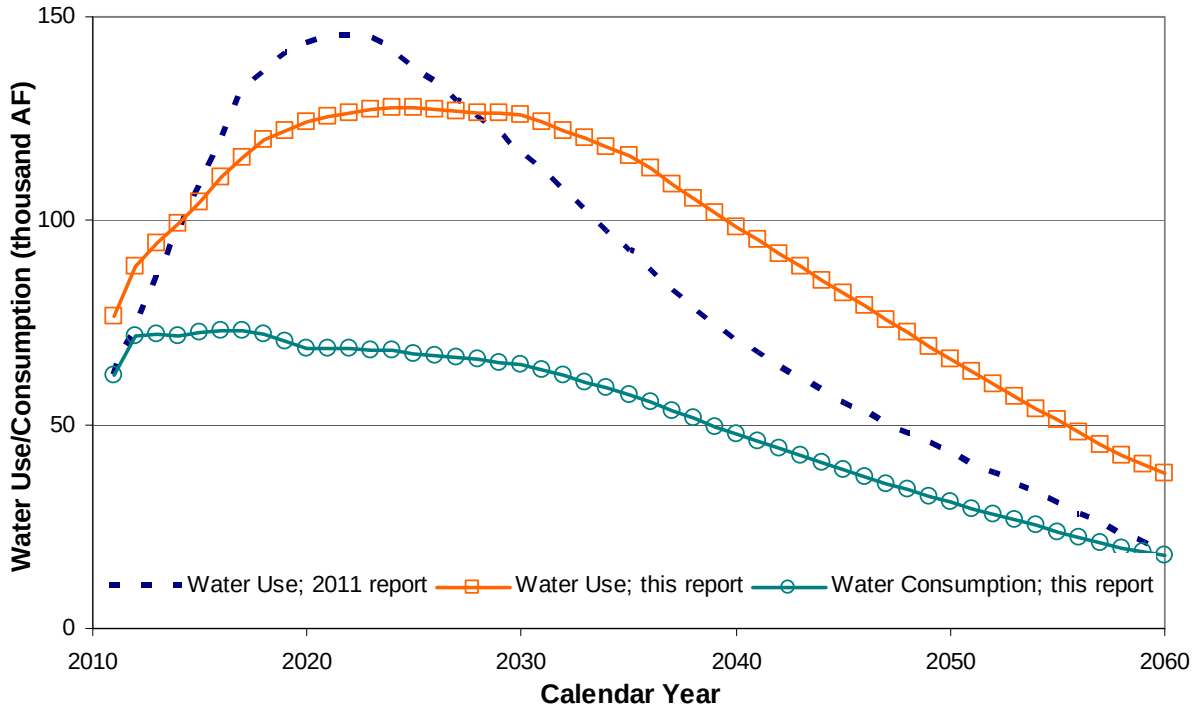


Figure ES2. State-level projections to 2060 of hydraulic fracturing water use and fresh-water consumption and comparison to earlier water projections.

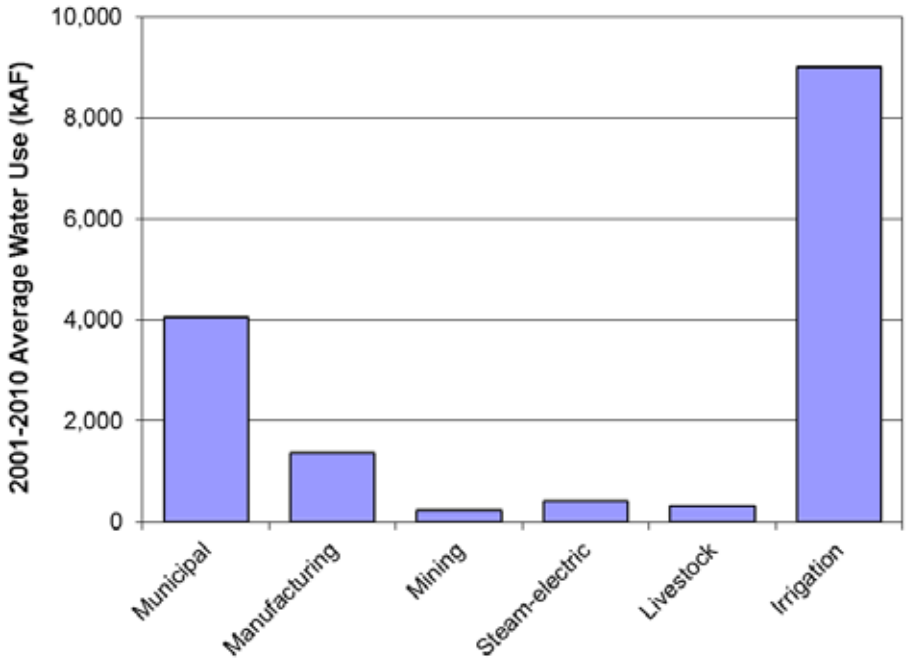


Figure ES3. Average state level water use (all categories) in 2001-2010.

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Acronyms

AF	Acre-foot
BEG	Bureau of Economic Geology
EOR	Enhanced Oil Recovery
Fm.	Formation
GW	Groundwater
HF	Hydraulic fracturing
kAF	Thousand acre-feet
Mgal	Million gallons
PSD	Powell Shale Digest
RRC	Railroad Commission (of Texas)
SW	Surface water
TCEQ	Texas Commission on Environmental Quality
TDS	Total dissolved solids
TWDB	Texas Water Development Board
TXOGA	Texas Oil & Gas Association

I. Introduction

This work is an update of the "Current and Projected Water Use in the Texas Mining and Oil and Gas Industry" (Nicot at al., 2011) report released in 2011 by the Texas Water Development Board (TWDB) and prepared by the Bureau of Economic Geology (BEG). The 2011 report documents future and projected water use in all segments of the mining industry: oil and gas, aggregates, coal, and other industrial and metallic substances. In particular, it looked at three main water categories in the upstream segment of the oil and gas industry: drilling, waterflooding and enhanced oil recovery (EOR), and hydraulic fracturing (HF).

How is this report different from the 2011 Report?

This report focuses on HF water use and associated drilling; the information in the 2011 report relating to waterflooding and EOR water use as well as drilling not associated with hydraulically-fractured wells did not require updating. This update also benefited from more participation from the industry, especially for information not typically available or easily extractable from state records. We also have a longer record for many plays, indicating trends and allowing for better future projections. In addition, we presented three scenarios for water use and water consumption for each play (high, medium, low) as was done in Bené et al. (2007) but not in the 2011 report. Furthermore we made the distinction between water use and water consumption more explicit. Water use is the amount of water used in an operation regardless of the water source provided; water is either fresh or brackish. Fresh water is defined as any water with a total dissolved solids (TDS) content of <1,000 mg/L; the upper limit for brackish water is 35,000 mg/L, but often in this document the limit will be <10,000 mg/L. Water consumption is fresh water use excluding recycling and reuse. Reuse is understood as the water originating from previous HF operations whereas recycling is more general and could include, for example, produced water from conventional wells or waste water obtained from other industries or municipalities.

Scope of work

As in the 2011 report, this update's scope of work includes two main tasks: (1) documenting current (year 2011) and past water use from HF; and (2) estimating projected water use. Both tasks are completed at the county level for the entire state of Texas. Task 1 consists of gathering water use data and establishing statistics needed for the projection phase in the spirit of what was done in the 2011 report but with a more detailed processing of the data. Task 2 is to produce a projection of county- level water use to 2060 using previously derived statistics and input from the industry.

This current document is organized in the following way. We first describe the methodology and its caveats as well as the challenges to making projections. We then examine the 2011 water use and compare our new findings to the 2011 projections made in 2008 as a way to validate our approach. We then present projections to 2060 according to three scenarios: high estimates, most likely estimates, and low estimates.

II. Methodology

II-1. Historical and Current Water Use

We followed a methodology similar to that used in the 2011 report, making use of the IHS Enerdeq database (http://www.ihs.com/products/oil-gas-information/data-access/enerdeq/browser.aspx). The IHS data were cross-checked with information from individual companies (number of oil/gas wells, of vertical/horizontal wells, amount of proppant) through discussion with company experts. In addition to production data, the Enerdeq database contains completion information submitted by operators to the Railroad Commission (RRC) of Texas through the W-2 and G-1 forms for oil and gas, respectively. In the best cases, and as noted by statistics provided in forthcoming sections of this report, the database contains all information of interest to us: API number, location of the well, well geometry, amount of water used, and amount of proppant used. Because, across plays, the completeness of the data is variable and because typographical errors are not infrequent, we developed several indicators for quality control: water intensity (amount of water used per unit length of lateral or useful vertical section) and proppant loading (amount of proppant per unit water volume). When either water intensity or proppant loading for a given well is out of range, the well is flagged and obvious errors corrected (for example, reporting water use in gal but displaying bbl as the unit instead of gal). Details on the approach follow.

The three primary data types used to estimate HF water volumes include reported values of fluid and proppant used to fracture each well and the total well length over which fracturing procedures were performed. Data were extracted separately from the IHS database for individual producing formations having a significant number (> ~100 to 200) of wells located in Texas that were completed between January 1, 2005 and December 31, 2011 that upon preliminary accounting had been fractured using > 100,000 gal of fluids. These include the Barnett, Eagle Ford, Haynesville, Cotton Valley, and Olmos formations, and several formations in the Anadarko Basin (Granite Wash, Cleveland, Marmaton) and the Permian Basin (Wolfcamp, Spraberry, Canyon, Clear Fork, San Andres, and Grayburg). For this analysis, the Wolfcamp and Spraberry were combined and the San Andres and Grayburg were combined.

As we did in the 2011 report we relied on the IHS database to recognize the currently active plays by downloading basic information on all wells drilled in Texas since 2010 (included early 2012 but with many gaps in the reporting). Our interest was not in computing water use but in determining those plays with enough activity to warrant a more detailed study. Many additional wells were fractured in other plays and did count toward the total water use in 2011, but they were not part of the detailed analyses of those plays cited earlier. Those minor plays are, however, accounted for in the general Gulf Coast and Permian Basin count.

II-1-1 Indicator for Quality Control

For producing formations having a sufficient number of wells completed during this period, the data were analyzed by annual intervals. Wells having actual or estimated total HF water use of <100,000 gal (i.e., small-scale traditional fracturing performed primarily on vertical/directional wells) were omitted from calculations as they account for comparatively insignificant water volumes compared to the fracturing currently being practiced in many plays. This minimum

volume distinction was applied to vertical/directional wells only, and all horizontal wells were included in the estimates.

Critical evaluation and editing of the raw data was required. The purpose of the editing process was, through a step-wise logical procedure, to exclude wells that used or (in the absence of accurate data) were likely to have used <100,000 gal of HF fluids while retaining and accounting for wells that used or (again, in the absence of accurate data) were likely to have used ≥100,000 gal of HF fluids. For many wells, one or more of the reported data values is absent, incomplete, or inaccurate, due either to clerical errors or to partial reporting (omission errors). Clerical errors include the incorrect assignment of units (gal vs. bbl, lb vs. ton, etc.) and/or typographical errors. Omission errors primarily include the non-reporting or under-reporting of fluid volumes (proppant amounts seem to be accurately reported much more consistently than fluid volumes).

The data were screened for errors by examining ratios between the different values, including the total reported volume of fluids used per linear foot of the total fractured well depth interval (water use intensity, gal/ft), the total mass of proppant per total volume of HF fluids (proppant loading, lb/gal), and the total mass of proppant per linear foot of the total fractured well depth interval (proppant intensity, lb/ft). These ratios were examined for outliers and inaccuracies by sorting hierarchically through the data based on the various ratios. Edits were performed on the raw data where rectifiable errors could be identified, the most prevalent consisting of modifying units where such changes resulted in ratios consistent with other similar wells. In some cases, sufficient details were reported in the data comments to correct inaccurate data values, although this type of edit was extremely limited.

In general, proppant loading (lb/gal) was used as the primary data screening ratio because of the generally consistent reporting of total proppant amounts. HF fluid volumes resulting in proppant loading values (average of all stages) >5 lb/gal were deemed as under-reported. Barring a unit's error, these values generally reflect reported fluid volumes that include only acid treatments and in some cases raw gel product volumes and do not also include the volumes of water used. For vertical/directional wells having reported proppant amounts and with absent or under-reported HF volumes, wells with <100,000 lb of proppant were excluded from the estimates based on an assumed 1.0 lb/gal loading ratio.

A finer level of resolution in the water use data could be achieved by binning the hydraulic fracturing stages into slickwater, gel, and cross-linked gel systems with the latter two having a smaller water use intensity. Unfortunately the database does not allow for an accurate count in each category. The information, however, was used in a qualitative way, checking its consistency with common practices in a play.

Following the data screening and editing procedures, the data were classified into two main groups: 1) wells judged to have accurately reported fluid volumes and 2) wells judged to have inaccurately reported fluid volumes. The average (annual) water use intensity (gal/ft) values of the Group 1 wells were multiplied by the (annual) sum total fractured length (ft) of the Group 2 wells to produce annual estimates of the total water use of the Group 2 wells. The average intensity values represent truncated averages based on 90% of the data that were calculated by eliminating values less than the 5th percentile or greater than the 95th percentile of the Group 1 population to reduce the impacts of extreme values. The Group 2 annual total estimates were then added to the Group 1 annual total values to produce estimates of actual annual total water

use. Values are reported for the major producing formations listed above by year and by county. County locations were assigned based on the wellhead coordinates.

A separate estimate using the same procedures was calculated for the HF water used during 2011 for all wells meeting the minimum 100,000 gal criteria but that were not completed in one of the producing formations listed above and for which insufficient data exist for temporal trend analysis.

II-1-2 Hydraulically-fractured Length

HF lengths for individual wells were determined using five approaches, each relying on different information in the database. All five approaches were applied to varying degrees to determine horizontal well HF lengths while only the first two were applied to vertical/directional wells. The first approach used the difference between the minimum and maximum reported test treatment depths and is referred to as the "test" length. This was the primary length used in an estimated minimum of 95% of all wells. The second approach used the difference between the minimum and maximum perforation depths, which was identical in most cases to that of the test length and is referred to as the "perf" length. The "perf" length was used in place of the test length in a few cases that resulted in more realistic use intensity values. The test and "perf" lengths are considered to be the most accurate length information available for most wells.

A third approach utilized the survey information and is referred to as the "survey" length. In this approach, the angle relative to the horizontal plane between successive well survey points was calculated. The horizontal length of the well was determined as the difference between the minimum depth at which that angle became less than 2.5 degrees and the maximum well depth. This approach also provided the average depth of the horizontal well section and additionally the beginning and ending X-Y coordinate locations of the horizontal well section used to map well density in GIS for the various plays. If no information was available to calculate a test or perf length, the survey length was considered to be the next-best available length information. In most cases where all three were available, the survey length is in good agreement with both the test and perf lengths. This value was used only in a few cases where neither a test nor a perf length was available.

A fourth length value was calculated as the difference between the reported driller's well depth and the bottom hole true depth, referred to as the "true value" or "TV" length and a fifth length value was calculated as the simple horizontal linear distance between the X-Y coordinates of the well surface and bottom hole coordinates ("GIS" length). Both of these values are considered to be only general estimates of the horizontal section length and were used in a very limited number of instances where more accurate information was not available. For a very few instances (<<1%) no length values were available for a given well. In these cases, the annual (truncated) average well length for that producing formation was assigned.

The fourth and fifth approaches, simpler to use, were adopted in the 2011 report. The HF water intensity for horizontal wells is computed slightly differently from the approach in the 2011 report. Instead of using the distance between the wellhead of the toe of the lateral, we used a shorter distance defined by the operator-defined "test length" more representative of the true length of the lateral. The test length is consistent with the "test" length but consistently smaller by 10 to 25%. The lateral length value matters as it used to compute water intensity, itself used to make projections. There is relatively little difference between the different approaches (Figure 1)

but the "test" approach used in this document is systematically smaller than the "GIS" approach used in the 2011 document, that is, water intensity values reported in this document are systematically greater than those in the 2011 report. The median value of water intensity using the "test" and "survey" approaches are 26% and 23% larger than the "GIS" median value (Figure 2) in the Barnett Shale play. The "test" water intensity median in the Eagle Ford play is 16% larger than the "GIS" median value (Figure 2d).

II-1-3 Beyond the Database

In the 2011 report we made the explicit distinction between shale plays and tight gas plays. Although, as explained in the 2011 report, there are real differences between them, from an operational standpoint the difference is blurred (for example, wells taping Wolfcamp shale oil and Spraberry tight oil) and, in this update, we did not try systematically to assign one of either category to some plays.

For each of the plays with sufficient data we extracted yearly information, presented in the Results Section, about:

- Total number of wells
- Total water use, including estimation of data gaps
- Average/median length of laterals
- Water use in Mgal/ft
- Water intensity in gal/ft
- Proppant loading in lb/gal

The IHS database provides only water use, that is, the amount of water used during a given HF job regardless of the water source(s). In actuality, water can come from several sources. It can be "new" water or it can also be recycled or reused water. "New" water can be surface water or groundwater or it can be from an alternative source such as municipal water or treated waste water. Water also be fresh (<1,000 mg/L) and its use can directly compete with other more conventional users (municipal use, irrigation use). It can be brackish or even more saline than sea water (that is, >~35,000 mg/L). Water consumption is simply defined as the water use which is not from recycled or reused water and from which brackish and saline water use is taken out. Note, however, that this simple definition does not capture a more complex reality. Use of brackish water in areas with limited fresh water supplies could compete with conventional users. This document does not try to sort out such issues; we simply define water consumption as water use minus recycled/reused water volumes and minus brackish or saline water volumes.

Access to detailed information about water sources on the provider side is difficult. Large water suppliers do not necessarily track the ultimate usage of their water. Groundwater conservation districts (GCD's) do not always collect information about withdrawal amounts and eventual use of the water. A request to the Texas Commission on Environmental Quality (TCEQ) on reuse of treatment water yielded a helpful list of facilities but not the amount of water transferred, and further this does not account for direct reuse at a site. The demand side, that is, operators, is very fragmented.

We collected information not present in the IHS database but of interest to TWDB and the general public about: (1) nature of the water source (river, lake, city water, groundwater, stock pond/gravel pit / quarry, wholesaler, treated industrial waste water) and it status (private, public). The ultimate goal is to determine the groundwater and surface water (GW/SW) split. Optimally,

this issue would be resolved at the county level but it may not be possible; (2) amount of water injected from reuse of flow back water, recycled water can include water from commercial and municipal waste water treatment facilities; (3) TDS of the new water [fresh (<1000 mg/L), slightly brackish (1000-3000 mg/L), brackish (3000-10,000 mg/L or 10,000-35,000 mg/L), saline (>35,000 mg/L)].

In this document, we applied to all counties within a play / region the same brackish water use, recycling/reuse fraction, and GW/SW split. Undoubtedly, this is an approximation but the amount of information available does not allow accurate assessments at the county level.

II-2. Future Water Use Projections

The 2011 report followed a mixed approach to estimate projected water use, the so-called resource-based and production-based approaches. Although both approaches are somehow interdependent, we believe that the resource-based approach gives the best results and is used in this document. As described in more details in the 2011 report, it consists of four steps:

(1) Gather historical data in terms of average well water use and average well spacing. It is important to establish these elements through time to see trends rather than just focusing on the past few months.
(2) Estimate ultimate well density across the play; it is a function of several factors, such as geological prospectivity (for example, within play core or not, shale thickness) and cultural features (urban/rural). In this step, ultimate boundaries of the play are identified.
(3) Compute approximate total number of wells needed.
(4) Distribute through time and space, constrained by the assumed number of drilling rigs available (see earlier comment).

After obtaining water use, correction factors to account for recycling/reuse and use of non-fresh water are applied. We asked industry operators for projected recycling/reuse, brackish water use, and groundwater / surface water split in 2020. Given the rapid pace of change in the industry, the values obtained are somewhat speculative. Although not a guarantee for accuracy, those values are, however, consistent with what industry observers report and consistent with our own knowledge of treatment techniques and state of surface water and groundwater withdrawals across the state. The basic reporting unit for the water use projections is the county. Projections for recycling / reuse, brackish water use beyond 2020 to 2060, were made accounting for the typical current volume of flow back (limiting reuse) and for brackish water resources / lack of fresh water in the area of interest.

As discussed in the 2011 report, despite our best efforts, it is likely that the projected water use amounts will be more accurate at the play than at the county level. As done in the 2011 report, we did not assume any repeat HF, as discussions with industry experts and recent publications (Sinha and Ramakrishnan, 2011) suggest that little repeat HF will take place.

The 2011 report provides only one annual estimate. However, in an earlier report on the Barnett Shale only (Nicot and Potter, 2007; Bené et al, 2007), BEG made use of high, medium, and low water use scenarios. The different scenarios were based on various level of prospectivity and anticipated gas price. This update also makes use of three scenarios, high, most likely, and low water use, but in addition to prospectivity and gas price, they take into account level of recycling/reuse and use of brackish and saline water.

II-3. Notes on Collected Information

We obtained information on all the major plays, some with better coverage, by contacting operators. Fraction of HF wells drilled by contacted operators in the 2010-2012 period is documented by play and provides an estimate of the uncertainty. The coverage (Table 1) was calculated by adding the number of wells completed in the 2010-early 2012 period by contacted operators and normalizing that sum by the total number of wells completed during the same period. We collected information about recycling/reuse, use of brackish water, surface water/groundwater split. Coverage varies from 40% (Barnett Shale) to 10.5% (Permian Far West). Consistency in information from operators in a given play suggests that even low percentages are representative of the industry as a whole in that play despite some variability among operators (Figure 3). The figure shows a slight overall increase in water use intensity with increasing depth but it also shows that operators can have different approaches.

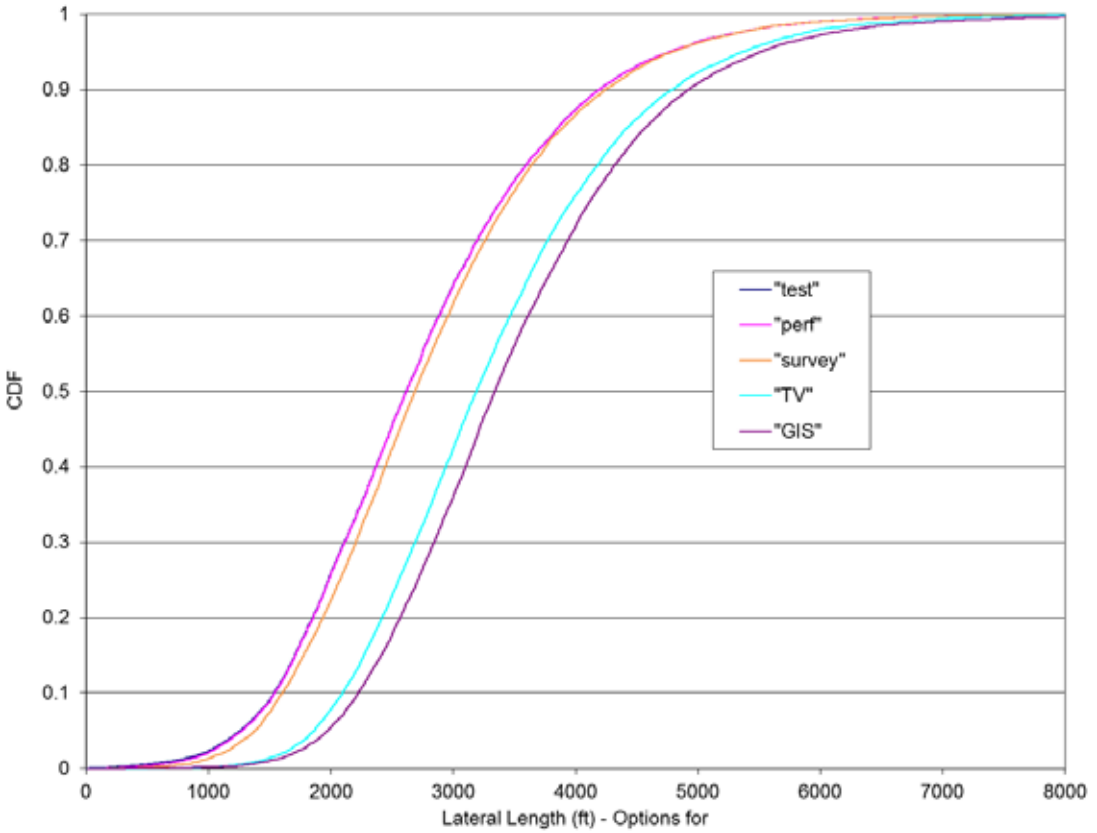


Figure 1. Comparison of five approaches to computing lateral length (Barnett Shale play).

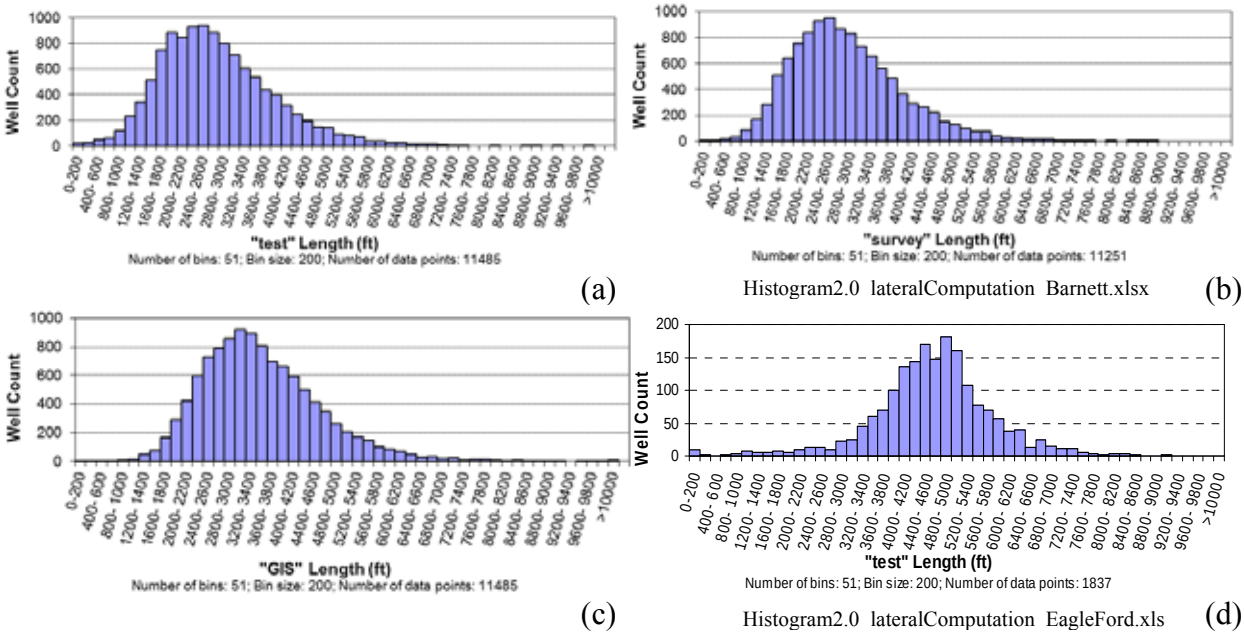


Figure 2. Histograms of lateral lengths according to various approaches: (a) “test”; (b) “survey”; (c) “GIS” (Barnett Shale play); and (d) “test” (Eagle Ford Shale play).

Table 1. Representivity of collected information

Play/Region	Consumption information (%)
Permian Far West	10.5%
Permian Midland	23%
Anadarko Basin	11%
Barnett Shale	40%
Eagle Ford Shale	31.2%
East Texas Basin	14.5%
All Plays	27.2%

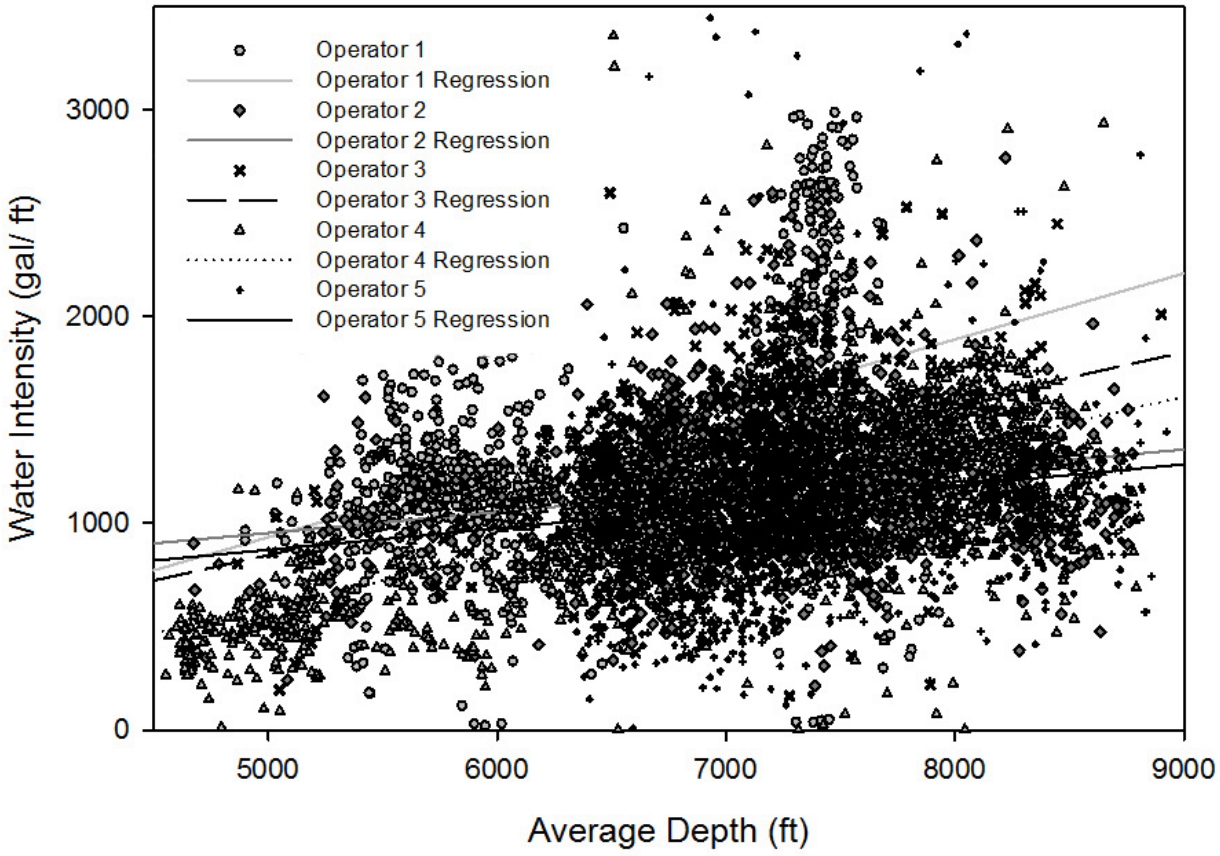


Figure 3. Water use intensity in the Barnett Shale play, showing comparison among between top operators in the play.

III. Historical and Current Water Use

After a short description of the major HF plays in Texas (Section III-1), we present water use and consumption numbers (Section III-2) that we compare to findings of the 2011 report (Section III-3). We also briefly address drilling water use (Section III-4).

III-1. Play Description

In this section we describe relevant features of each play which will then be used in the Projections Section (Section IV). Note that water use intensity and proppant loading values represent an average of the sometimes time-varying mix of slickwater / gel systems applied to the play at a given time. For example, a decrease in water use intensity may mean a better water efficiency in a technique or a move to a more water-efficient technique.

III-1-1 Barnett Shale

The Barnett Shale is the first in Texas and around the world to submit to intense slick-water HF since the mid-1990's, first using vertical wells. After a transition period, Barnett Shale operators use currently horizontal wells almost exclusively. After a strong growth in the mid-2000's (>2000 wells completed per year), the play has seen a relative decrease in the total number of wells completed in a year (Figure 4a) because of the reduced demand following the economic slump and the decreasing price of gas. Although drilling activity has abated at the edges of the play core, it is very vigorous in the core itself (Denton, Johnson, Tarrant, and Wise counties) and has considerably picked up in the so-called combo play in the northern confines of the play in Cooke and Montague counties. A weekly newsletter, the Powell Shale Digest (PSD; May 29, 2012) noted a sharp increase in oil production since mid-2010. Substantial amounts of oil and condensate have made those counties attractive to operators. Overall the total amount of water used is relatively steady at 25 kAF/yr (Figure 4b). The Barnett play is the Texas play with the highest degree of reporting water use at >90% (Table 2). Note that the bottom four plots of composite Figure 4 (as well as on similar figures in this document) show the fraction of wells used to compute the parameter on the secondary axis. High well reporting, allied with the large number of wells, gives us confidence that the water use values are particularly accurate in this play. The length of the laterals has been slowly increasing in the past few years (~3,500 ft in 2011) with a concomitant water use increase (Figure 4c and d). However water intensity (water amount per unit length) has stayed steady at ~1,200 gal/ft (Figure 4e). Note that the water intensity as reported in this document is higher than that reported in the 2011 report because of a slight change in computing it (see Section II-1-2). In contrast to water intensity, proppant loading has been increasing slightly over time to ~0.8 lb/gal in 2011 (Figure 4f).

In order to better understand water intensity and in an effort to modulate it across a play, we plotted water intensity against depth and thickness (Figure 5a and c). The trend seems upwards with increasing depth and thickness but is very noisy and tenuous at best. Water intensity appears to be rather dependent on the well operator (Figure 5b) and, thus, somehow difficult to vary across a play. Nevertheless, spatial distribution of water intensity shows a higher intensity in Denton County and in the eastern half of Wise County, areas in which the Barnett is the deepest as well as in Montague County in the oil window (Figure 6a).

In agreement with our methodology, it is also useful to understand the cumulative length of laterals in a given area or within a county. A key input to the projected water use is to assume

that the entire county will be hypothetically drilled up by parallel laterals extending from one side of the county to the other side and at regularly spaced intervals (at, for example, a 1,000- ft interval [see Nicot et al., 2011 for details]). Figure 6b displays such density of well laterals, which is fairly high in Johnson County and the southern half of Tarrant County. The average lateral spacing, which is simply the inverse of the lateral density, is shown in Figure 7 and detailed in Table 3 (it is calculated in those sections of the county with an actual shale footprint). The county with the highest relative cumulative length of laterals (Johnson County) yields an average spacing between assumed parallel laterals of ~1,700 ft. This is still removed from the operational distance between laterals of 1,000 ft or even 500 ft, suggesting that this county, despite its past activity will still see further significant activity as illustrated by the coverage gaps in Figure 8. The decrease in well completion activity in Johnson County as seen in Figure 9a is more related to price gas than to a true depletion of the resource in the county.

III-1-2 Eagle Ford Shale

The Eagle Ford Shale play has seen tremendous development in the past 2 years. Initially started as a new Barnett Shale, it quickly turned into a different type of play when the extent of the oil window became clear. In addition to the fast increase in wells completed (~1,400 in 2011) (Figure 10a) and the subsequent increase in water use at ~24 kAF in 2011 (Figure 10b), the Eagle Ford Shale has the unique feature among all the plays examined in this document to experience a sharp decrease in water intensity (Figure 10e) decreasing almost in half in 4 years to ~850 gal/ft in 2011. This is seemingly due to operational changes moving from high-volume slick water HF operations to gel fracs that can carry as much proppant with much less water. The use of cross-link gels for oil production requires a higher proppant loading (Fan et al., 2011). This decrease in water intensity combined with an increase in average lateral length (~5,000 ft, Figure 10c) still translates into a decrease in water use per well to ~5 million gallons/well (Figure 10d). Not surprisingly, the proppant loading has considerably increased to 1 lb/gal in 2011 (Figure 10f). The question we will not try to answer despite its relevance to water use projection is how transferable to other plays is this switch to gel fracs and whether it could happen elsewhere on a large scale. The percentage of wells with consistent data sets is only ~47% (Table 2), making the Eagle Ford data set more uncertain that than of the Barnett Shale.

The cross-plots of water intensity vs. depth and thickness are inconclusive and even misleading (Figure 11a and b). They show no real trend except perhaps a decrease in water intensity with depth. However, Figure 12a clearly shows a higher water intensity in the down dip sections of the play, suggesting an intensity as high as 1400 gal/ft in the gas-rich area and 800 gal/ft in the oil-rich area. Densities of lateral (Figure 12b) and average lateral spacing (Figure 13, Table 4) suggest that the Eagle Ford Shale play has two cores: next to the Mexican border in Dimmit, LaSalle, and Zavala Counties and south of San Antonio in Karnes and De Witt Counties. The low average lateral spacing (>10,000 ft) suggests that many more wells will be drilled and completed there in the future.

III-1-3 TX-Haynesville Shale and East Texas Basin

This document deals only with the Texas section of the Haynesville Shale. In East Texas the Haynesville is a deep gas play, despite a report that one company has located a liquid-rich area in the Haynesville in Panola County with 350 horizontal drill sites (PSD, May 29, 2012). These are expensive wells, but they are located in an area with multiple stacked formations amenable to

HF. The Texas section of the play has seen a quick increase in the number of wells drilled (~250 in 2011, Figure 14a) and a subsequent increase in water use (~1.6 kAF, Figure 14b). This play, with the Cotton Valley Fm., also in East Texas, has the smallest fraction of wells with usable data (32% in 2011, Table 2). Lateral length (~5,00 ft), well water use (~8 million gal/well), and water intensity (~1,400 gal/ft in 2011) have all increased in the past 3 years (Figure 14c, d, and e) whereas proppant loading has stayed stable at 0.8 lb/gal (Figure 14f). Water intensity as a function of depth and thickness does not show any reliable pattern (Figure 15). Water intensity (Figure 16b) and density of lateral (Figure 16c) are spatially correlated. The highest correlations are in Harrison County and where Shelby and San Augustine counties meet (Harrison, Shelby, San Augustine, and Panola counties are all in the TX-Haynesville core area). County-level average lateral spacing (Figure 17and Table 5) with a minimum value at ~24,000 ft suggests that many more wells will be completed in this play.

III-1-4 Permian Basin

The Permian Basin, comprising the Midland Basin to the East and the Delaware Basin to the West, with the Central Platform in between, has a long history of mostly oil production. It has also received much attention recently because of hydraulically fractured vertical wells in the so-called Wolfberry play (Wolfcamp and Spraberry, Figure 18). More recently, attention has shifted to horizontal wells in the Wolfcamp Shales (Figure 19), one of the source rocks of the many oil accumulations in the Permian Basin. Several other plays are also being hydraulically fractured in the basin such as the Canyon Formation (Figure 20), the Clear Fork Formation (Figure 21), and the San Andres (Figure 22 and Figure 23) among others.

The Wolfberry was the first play in the Permian Basin to benefit from the technological progress made in the Barnett Shale play. The wells are vertical and have grown from <500 wells/yr to >1,500 wells in 2011 (Figure 18a). The annual amount of water use had also increased to almost 8 kAF in 2011 (Figure 18b). Approximately 80% of the wells have consistently good data. As the length of the productive vertical section has increased from 1.500 ft to >2,500 ft in the past few years (Figure 18c), so has the average water use per well which is >1 million gal/well in 2011, relatively small volume compared to that of horizontal wells in shale plays. As productive sections become longer, the water intensity increased slightly to ~400 gal/ft (Figure 18e), but proppant loading remained constant at ~0.9 lb/gal (Figure 18f). Water intensity seems to be higher in the Wolfberry of the Delaware Basin (Figure 24a), but that basin contains very few wells (Figure 25a), (and they might even be misnamed). The well density is the highest in Glasscock and Reagan Counties.

Slick water horizontal wells have been jumped in 2011 from a low level of <50 wells/yr to 160 wells (Figure 19a), with a concomitant increase in total water use (~1.5 kAF in 2011, Figure 19b). Lateral length (~5,000 ft in 2011), well water use (~5 million gal/well in 2011), and water intensity (800 gal/ft in 2011) all increased too (Figure 19c, d, and e), but average proppant loading stayed steady at ~1 lb/gal (Figure 19f). Water intensity is higher in the center of the Midland Basin (Figure 24b), and the density of lateral is the highest in Ward County (Figure 25b) but the average lateral spacing is still very high at ~23,000 ft (Figure 26), which suggests that many wells remain to be drilled and completed.

Other, less publicized plays also received increased interest, as shown by water intensity rising or remaining steady (Figure 20e, Figure 21e, Figure 22e, and Figure 23e). Other plays, not targeted for the same scrutiny, have also seen a development of HF. They were included in a

miscellaneous file that included all fractured wells not included in a targeted play. Overall the Permian Basin has a high fraction (~85%) of wells with a consistent data set (Table 2), thus giving us confidence that that the water use values are relatively accurate (especially for those formations hosting a large number of wells).

III-1-5 Anadarko Basin

The Anadarko Basin contains several formations of interest, in particular the Granite Wash (Figure 27) but also the Cleveland and Marmaton formations (Figure 28 and Figure 29). Similarly to the development of the horizontal wells in the Wolfcamp in an area where HF was done on mostly vertical wells, the Anadarko Basin is seeing a shift toward horizontal wells. The Granite Wash has seen an increase from a few horizontal wells in 2006 to >300 in 2011 (Figure 27a) with a parallel increase in water use to <4 kAF in 2011 (Figure 27b). In the same time the length of the lateral has grown to ~4,500 ft (in 2011) (Figure 27c) and the average well water use to >5 million gallons (Figure 27d). Water intensity has reached a value of ~1,200 gal/ft (Figure 27e), but the proppant loading has remained steady at ~0.6 lb/gal (Figure 27f). The Cleveland and Marmaton horizontal wells display a similar evolution but for a smaller number of wells (~150 and ~40, respectively) and smaller water intensity at ~300 gal/ft (Figure 28e and Figure 29e). the fraction of wells with directly usable information was calculated at ~70% (Table 2). Water intensity as a function of depth failed to show a clear trend (Figure 30 and Figure 31).

Spatial distribution of Granite Wash water intensity (Figure 32a) and density of lateral (Figure 32b) confirms that Wheeler County is the most attractive county. At the county level, Wheeler County shows the smallest lateral spacing and plenty of room for additional wells (Figure 33 and Table 6). HF activities in the Cleveland and Marmaton Formations are focused on Hemphill, Lipscomb, and Ochiltree Counties (Figure 34 and Figure 35). Combining information from the three plays illustrates that the county with the smallest average lateral spacing (Lipscomb County) still allows for significant development at ~11,000 ft (Figure 36), as illustrated in Figure 37.

III-1-6 East Texas Basin

The East Texas Basin contains many formations susceptible to being hydraulically fractured. This section focuses on the Cotton Valley Fm., but, as was done for the Permian Basin and the Gulf Coast Basin, all water use data from wells in formations that were not part of the plays targeted for detailed study were still added to the total water use.

The Cotton Valley Fm. has been producing for decades and has been subjected to HF for almost as long. However, as observed in the rest of the state, there is a general shift from vertical to horizontal wells. Annual completions of vertical wells have been decreasing from ~1500 wells per year in 2007 to ~300 in 2011 (Figure 38a), whereas horizontal wells have been increasing from almost none in 2005 to ~100 in 2011 (Figure 39a). Total water use has followed the same path from ~1.5 kAF/yr to ~0 and from ~0 to 0.6 kAF/yr, respectively (Figure 38b and Figure 39b). In 5 years, the length of lateral has increased from ~1,000 ft to ~4,000 ft in 2011 (Figure 39c) with the associated water use increase to 4 million gallons per well in 2011 (Figure 39d). In the same period, water intensity has stayed steady at ~1,000 gal/ft (Figure 39e) and proppant loading has remained at ~0.8 lb/gal (Figure 39f). The overall representivity of the usable data set is at a steady ~70% for the horizontal wells but decreasing to only 25% for the vertical wells. A water intensity vs. depth cross-plot (Figure 40) displays no obvious trends but maps of well

density (Figure 41 and Figure 42) show that horizontal wells are being completed in the same areas as where the vertical wells were drilled and that there is a good overlap of the high density values.

III-1-7 Gulf Coast Texas

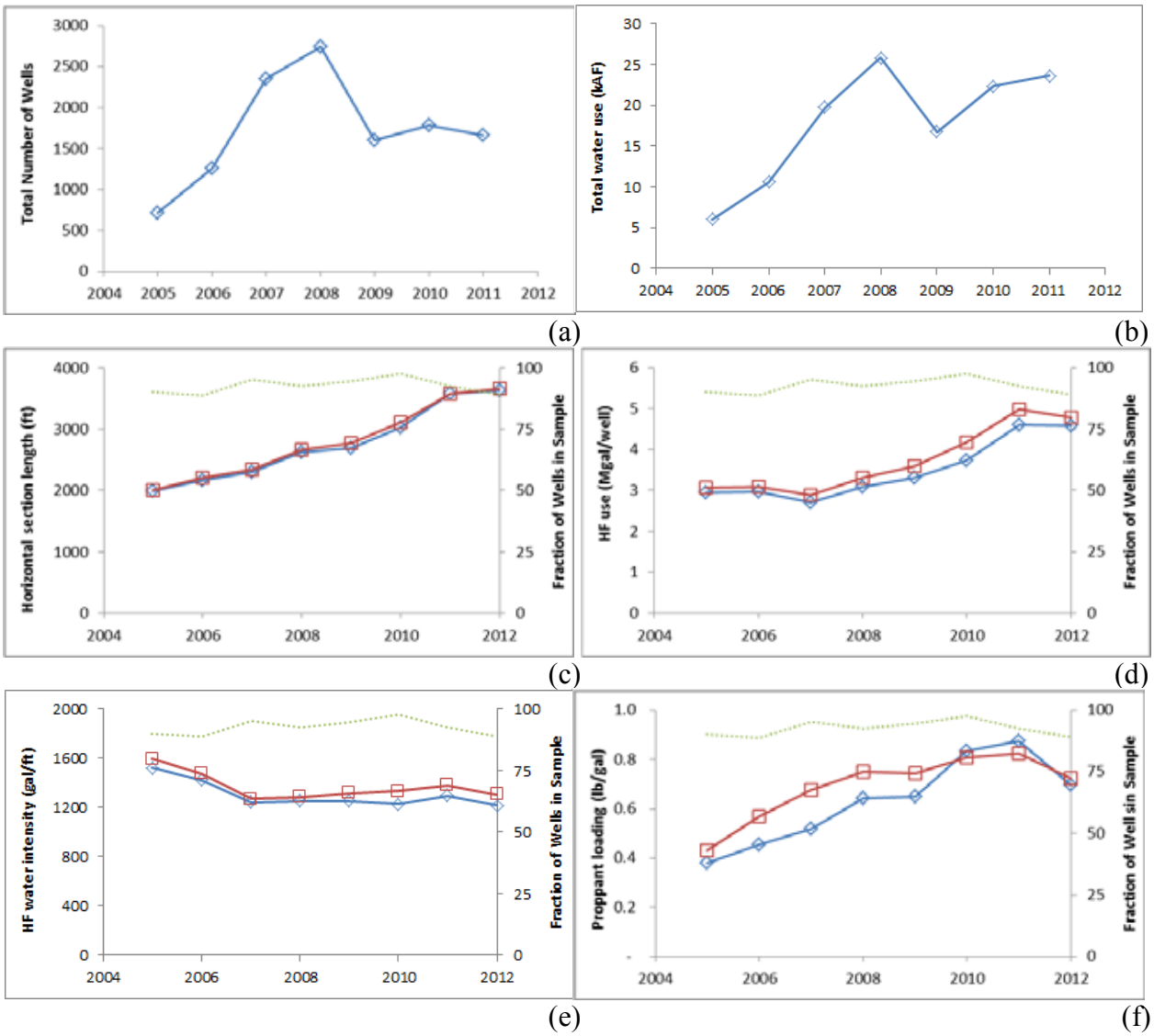
Similarly to the Permian Basin and the East Texas Basin, the Gulf Coast Basin, which includes many counties from the Mexican border to the Louisiana state line, contains several formations amenable to being hydraulically fractured. Each of these formations is not described here (for example, the Austin Chalk), but their water use is included in the total reported below. In this section, we document the Olmos Sands, where HF is taking place through horizontal wells. The annual number of completion is still low at 70 completions a year (Figure 43a) but growing and the total water use displays the same growth (~0.5 kAF in 2011, Figure 43b). Average lateral length has reached ~4,000 ft in 2011 (Figure 43c), and the average water use per well has increased to 4 million gal/well (Figure 43d). Although irregular through the years, water intensity has reached a value of ~1,000 gal/ft (Figure 43e) consistent with what has been observed elsewhere.

Table 2. Percentage of wells in each play or region that yielded a complete and consistent data set (water, proppant, length) from year 2011.

Play / Region	Percent
Barnett	92.7%
Eagle Ford	46.9%
Haynesville	31.8%
Cotton Valley	31.4%
Anadarko	69.4%
Permian Basin	84.9%

ResultsSummary_year2011.xlsx

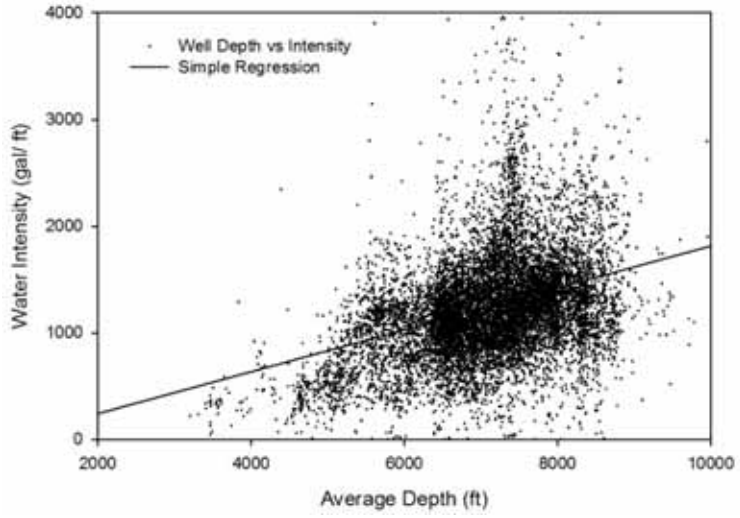
Barnett Shale:



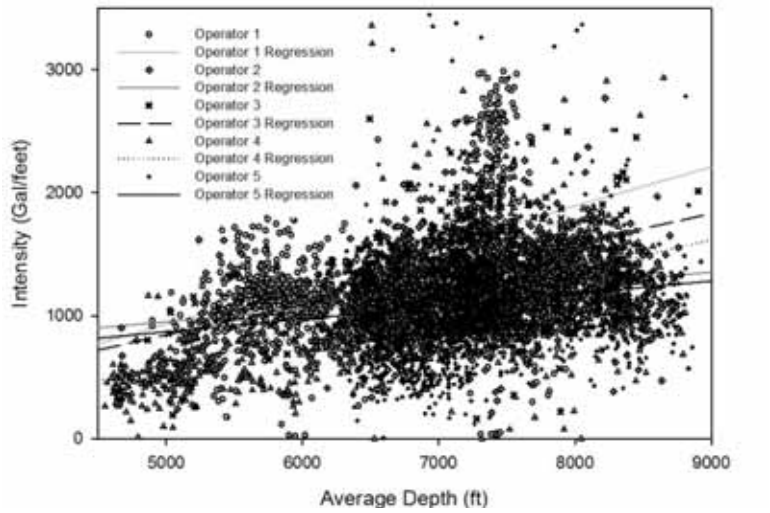
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 4. Barnett Shale horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

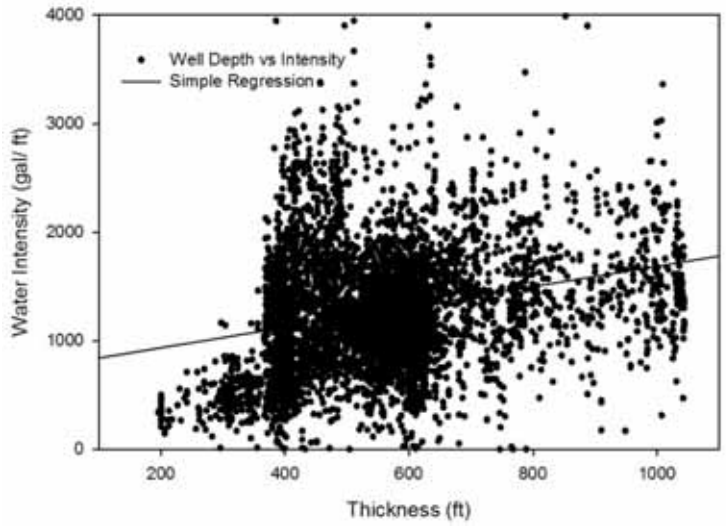
Barnett Shale:



(a)



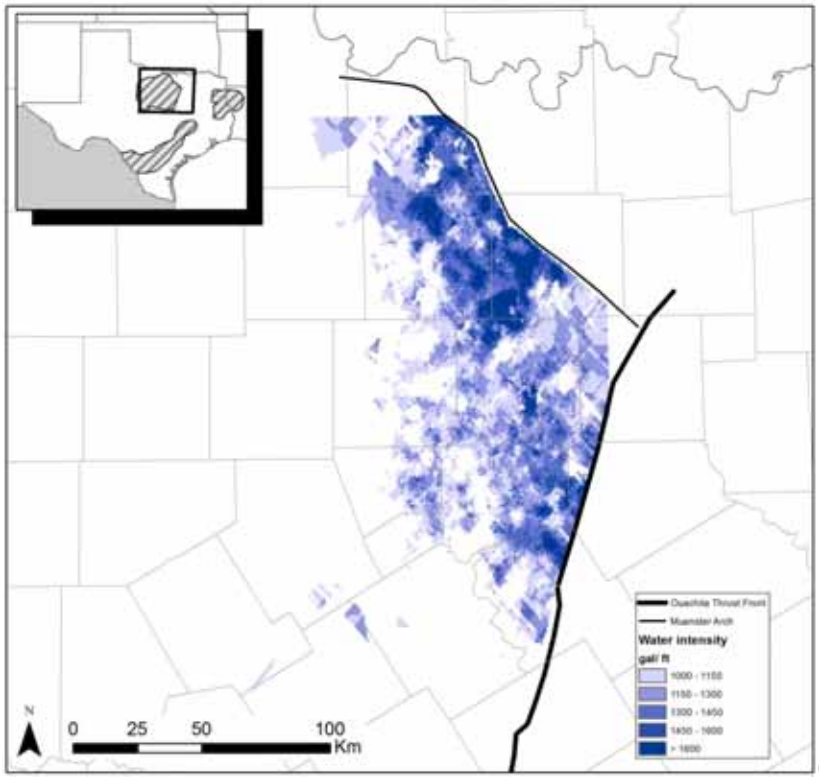
(b)



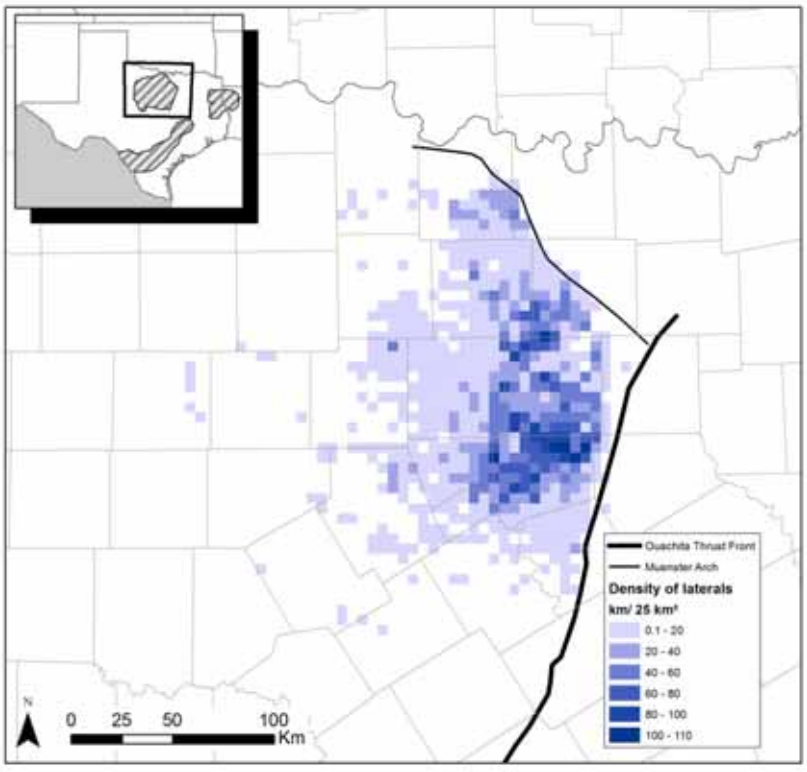
(c)

Figure 5. Barnett Shale horizontal water use intensity as a function of (a) depth; (b) operator and depth; and (c) formation thickness.

Barnett Shale:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 6. Barnett Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Barnett Shale:

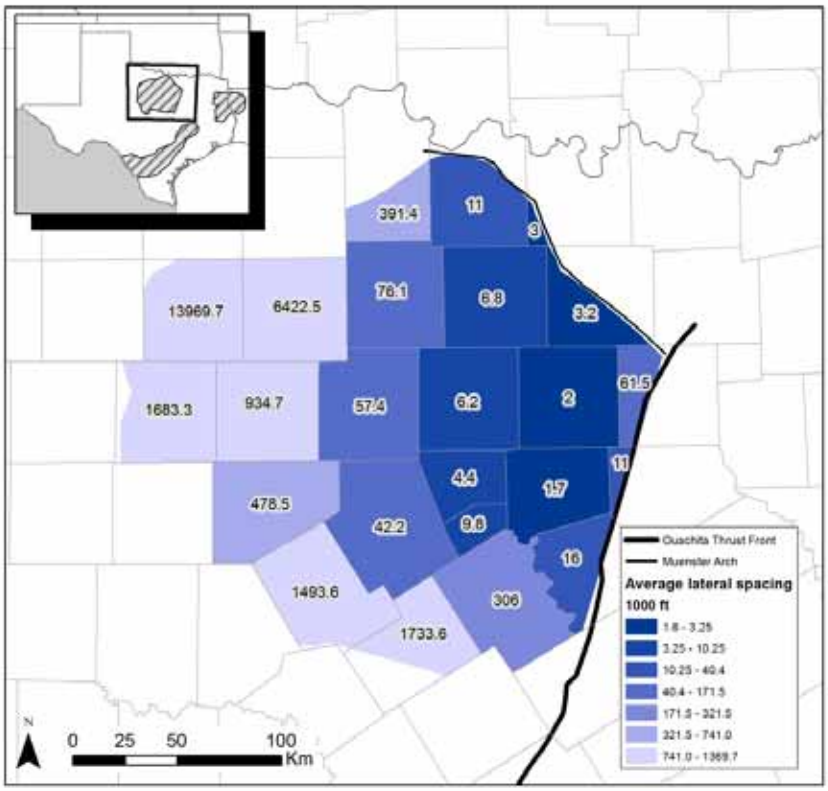


Figure 7. Barnett Shale county-level average lateral spacing.

Table 3. Barnett Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Johnson	1.94	1.69
Tarrant	1.66	1.98
Hood	0.75	4.35
Parker	0.53	6.20
Wise	0.48	6.77
Denton	0.47	6.99
Somervell	0.34	9.76
Others		>10×10^3 ft

Note: Average spacing = 1/ (lateral length density);
Counties are sorted by decreasing lateral length density

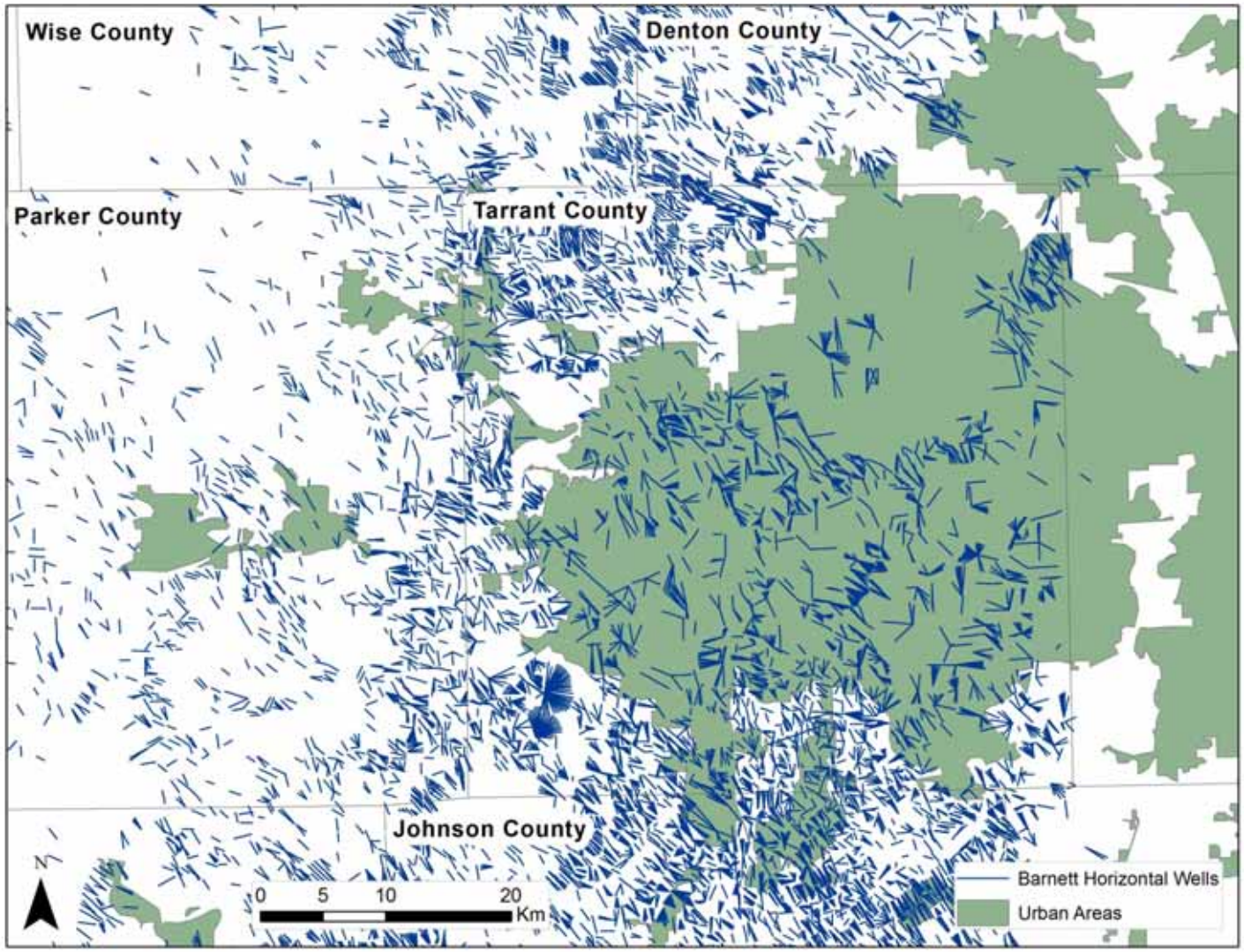
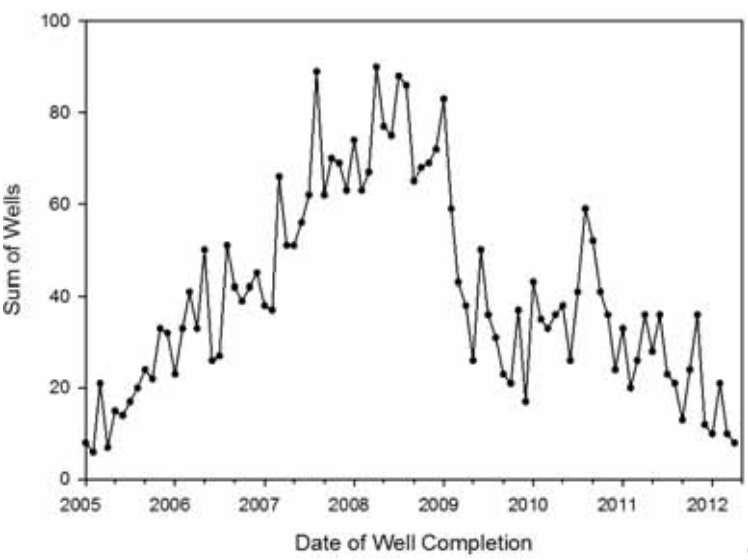
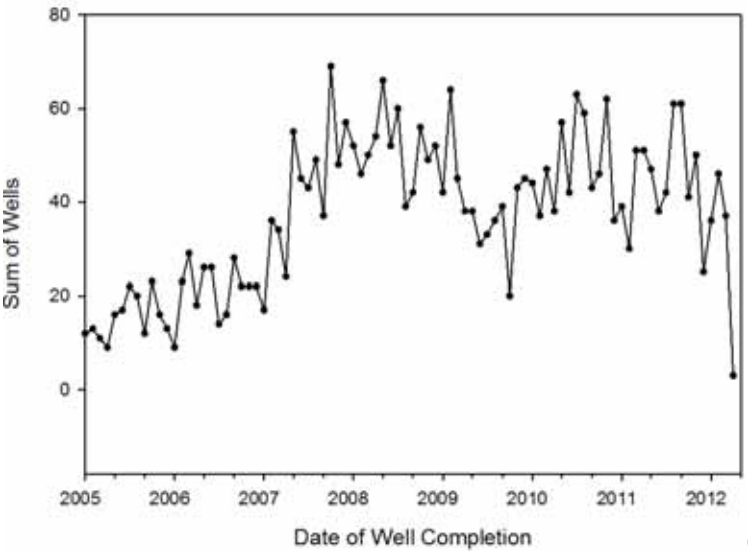


Figure 8. Map view of lateral expression of horizontal wells in the Barnett Shale centered on Tarrant County.



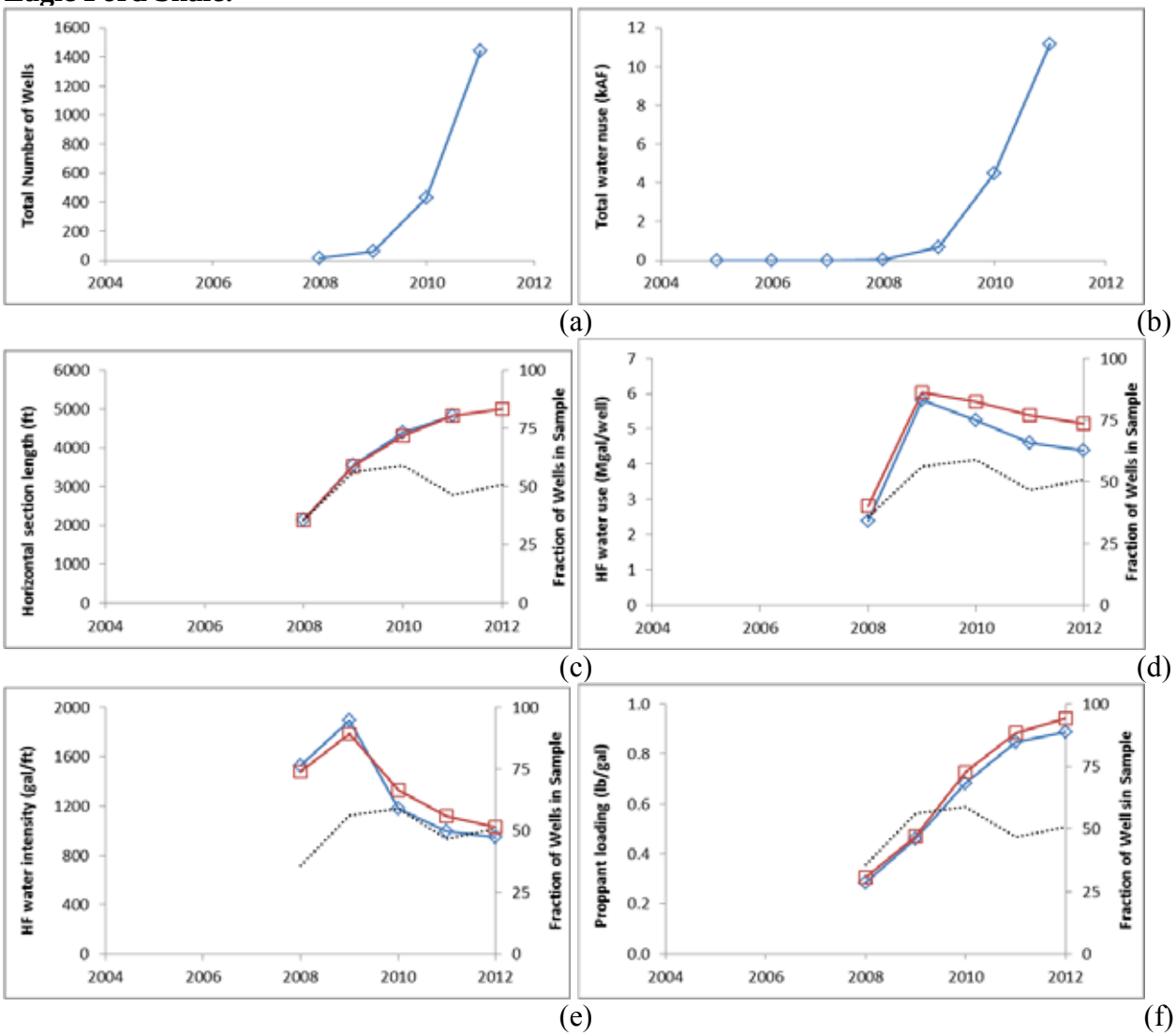
(a)



(b)

Figure 9. Annual well count in Johnson (a) and Tarrant (b) counties.

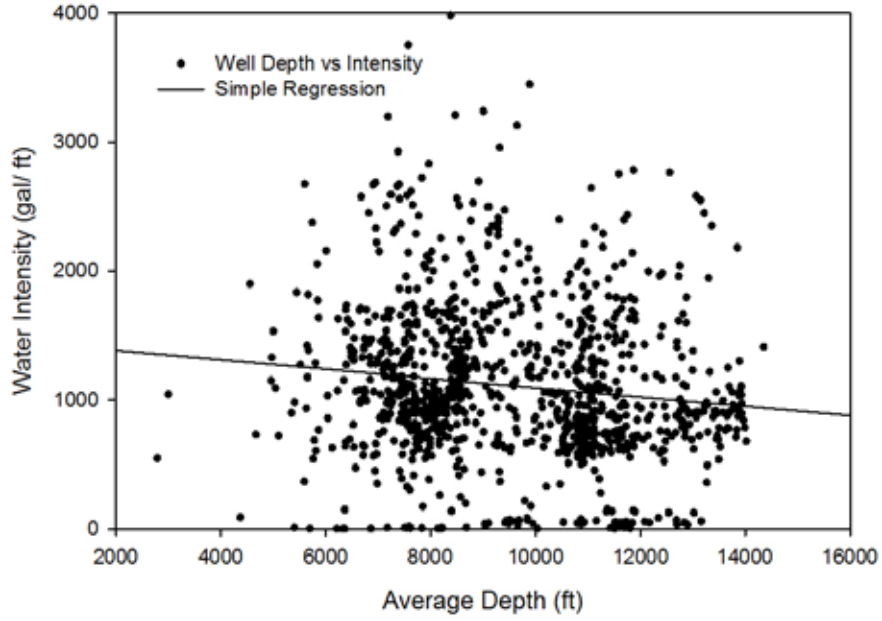
Eagle Ford Shale:



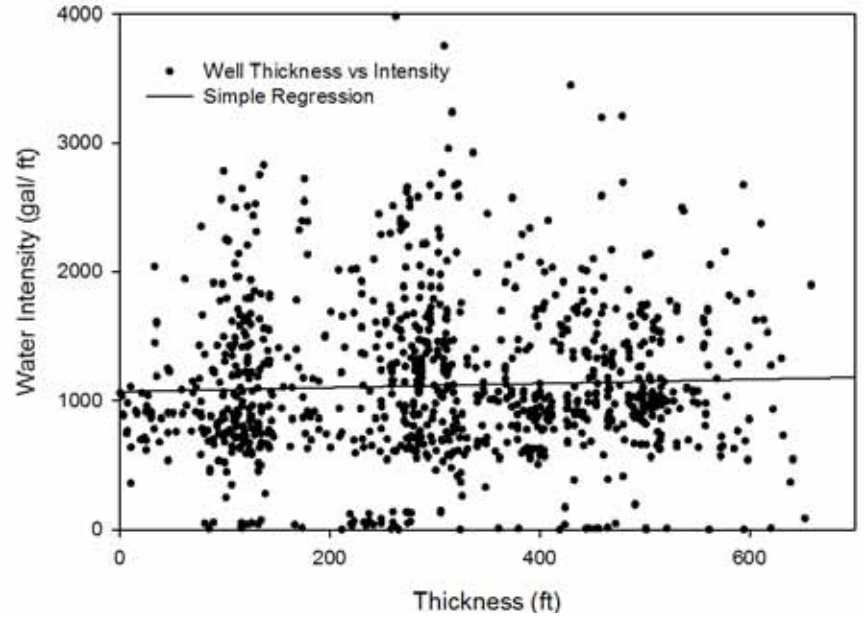
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 10. Eagle Ford horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Eagle Ford Shale:



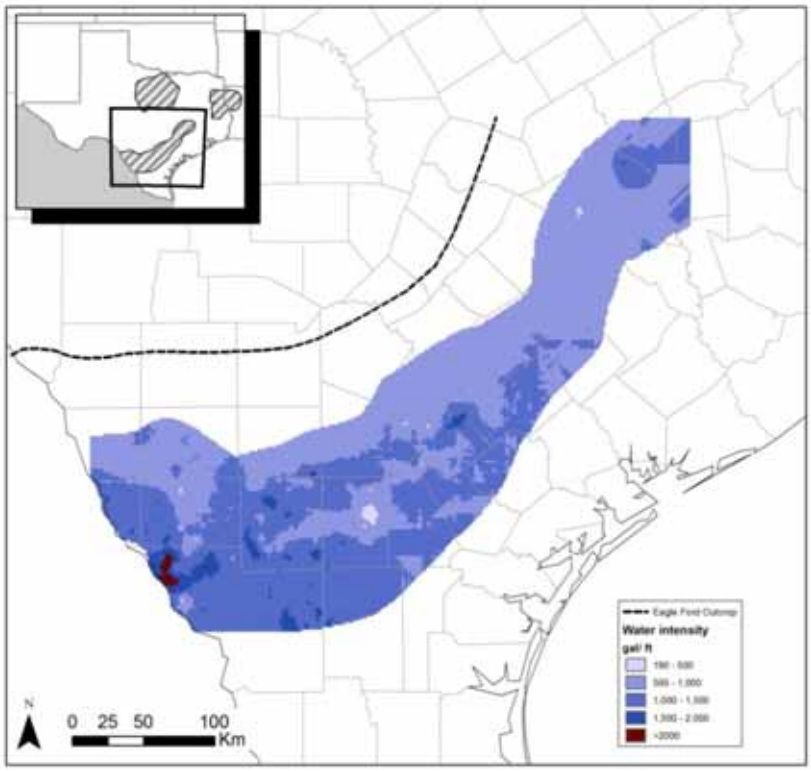
(a)



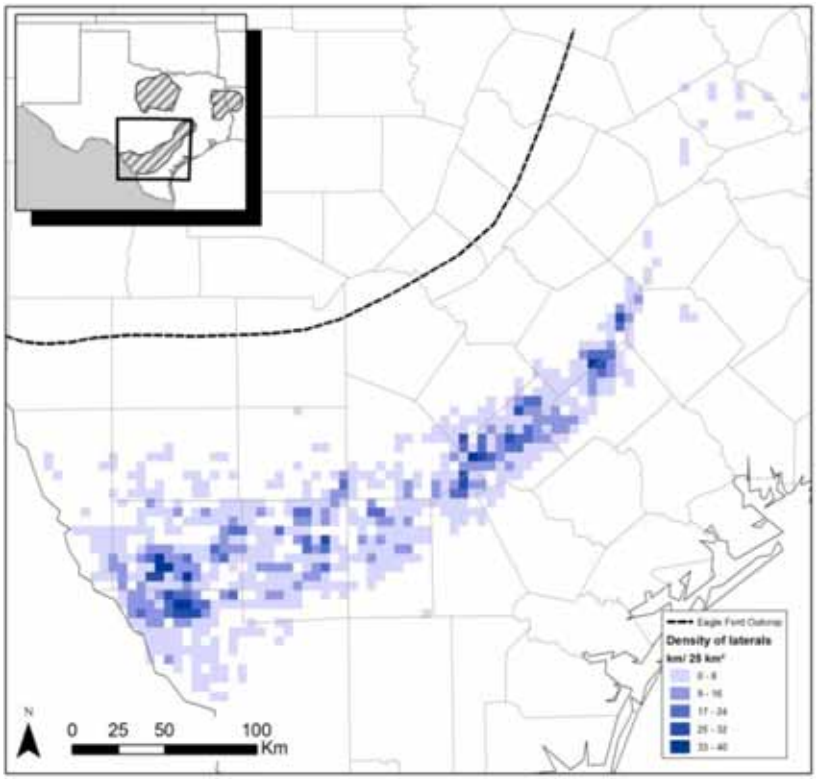
(b)

Figure 11. Eagle Ford Shale horizontal wells' water use intensity as a function of (a) depth; and (b) formation thickness.

Eagle Ford Shale:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 12. Eagle Ford Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Eagle Ford Shale:

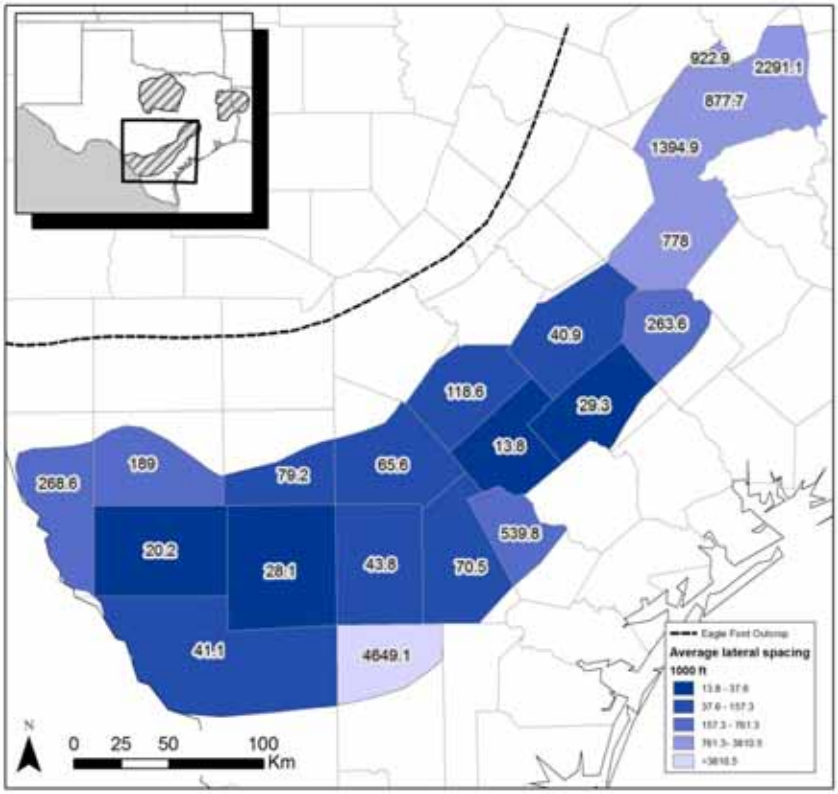
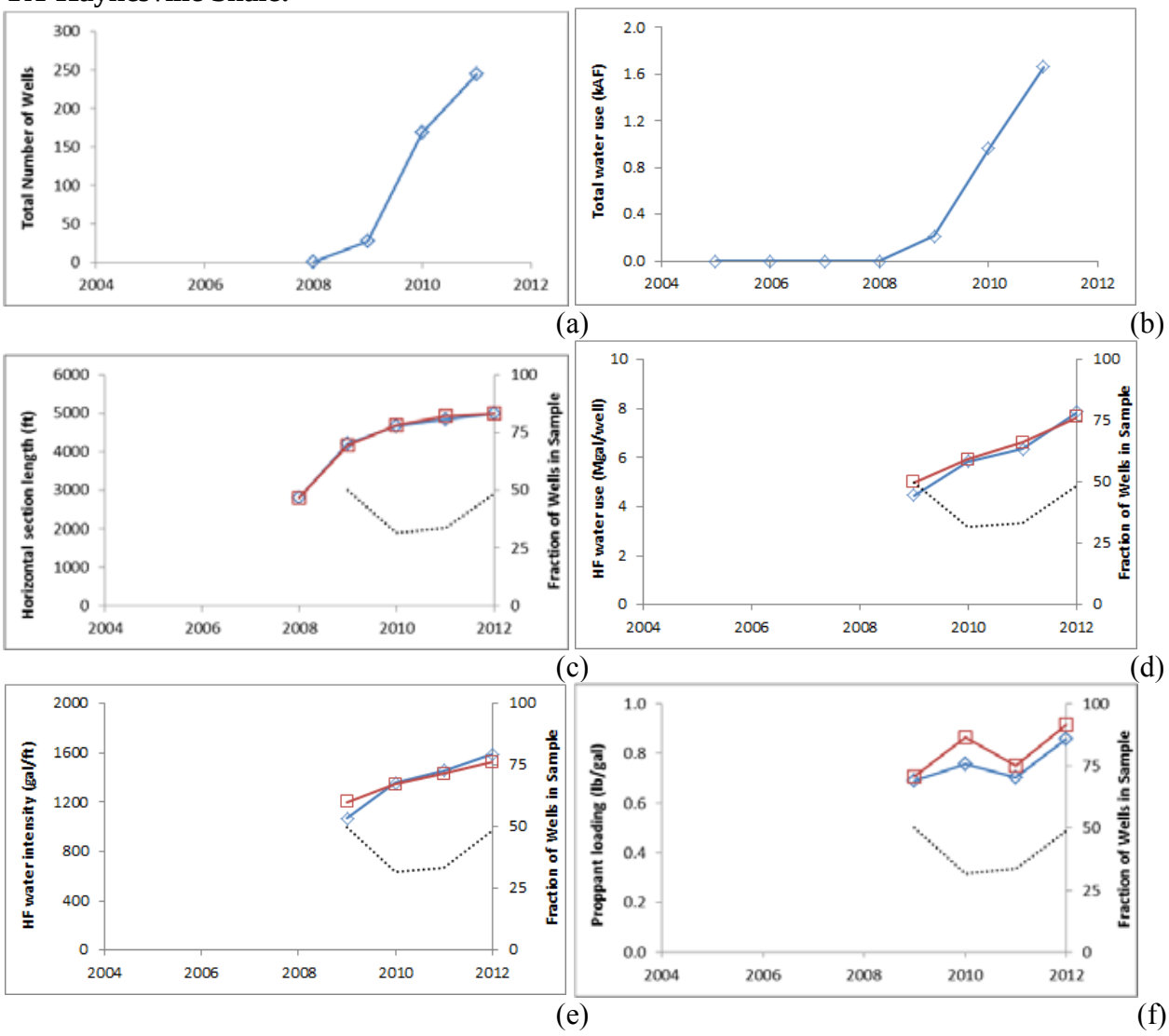


Figure 13. Eagle Ford Shale county-level average lateral spacing.

Table 4. Eagle Ford Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Karnes	0.236	13.93
Dimmit	0.162	20.30
La Salle	0.116	28.20
De Witt	0.111	29.63
Gonzales	0.080	41.01
McMullen	0.075	43.79
Webb	0.080	41.11

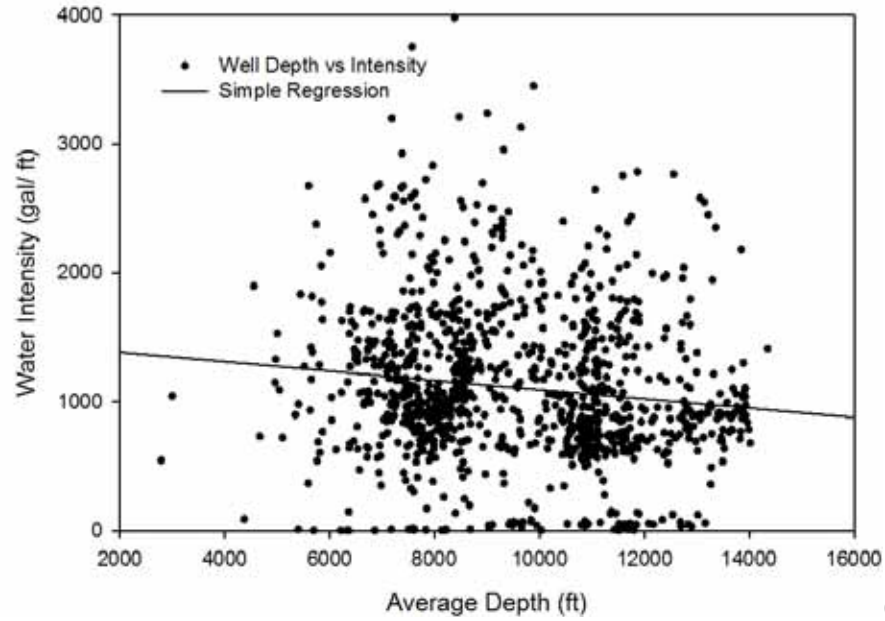
TX-Haynesville Shale:



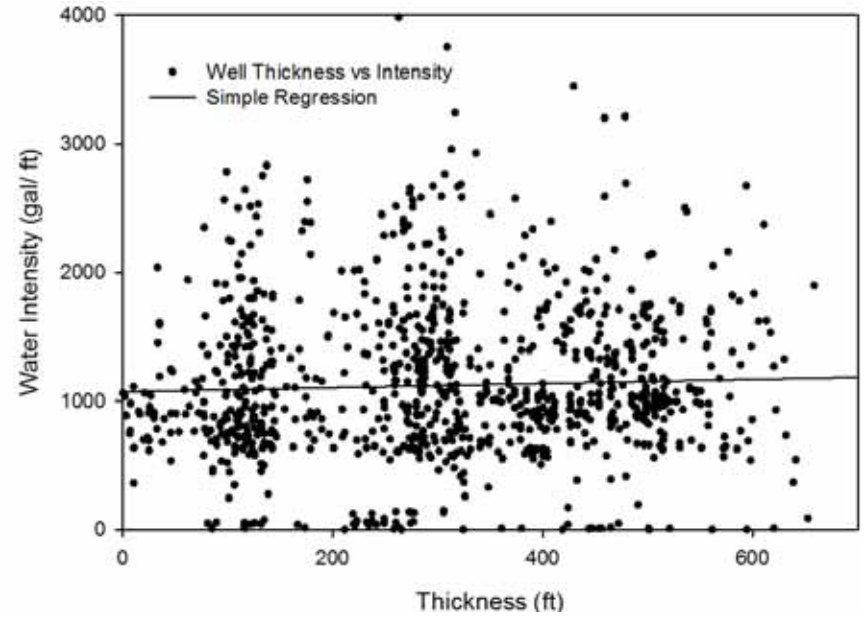
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 14. TX-Haynesville Shale horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

TX-Haynesville Shale:



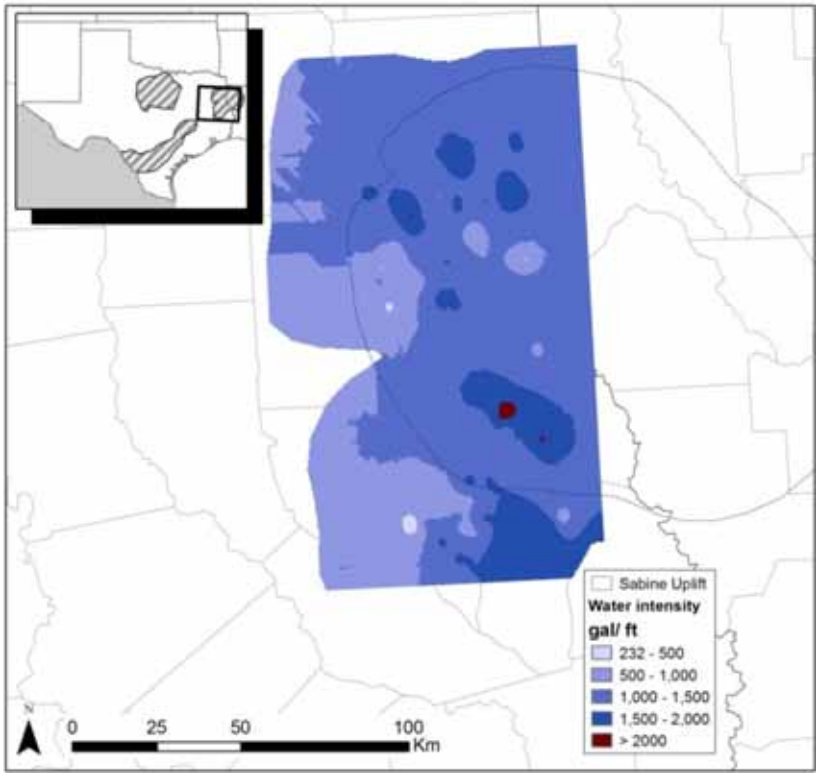
(a)



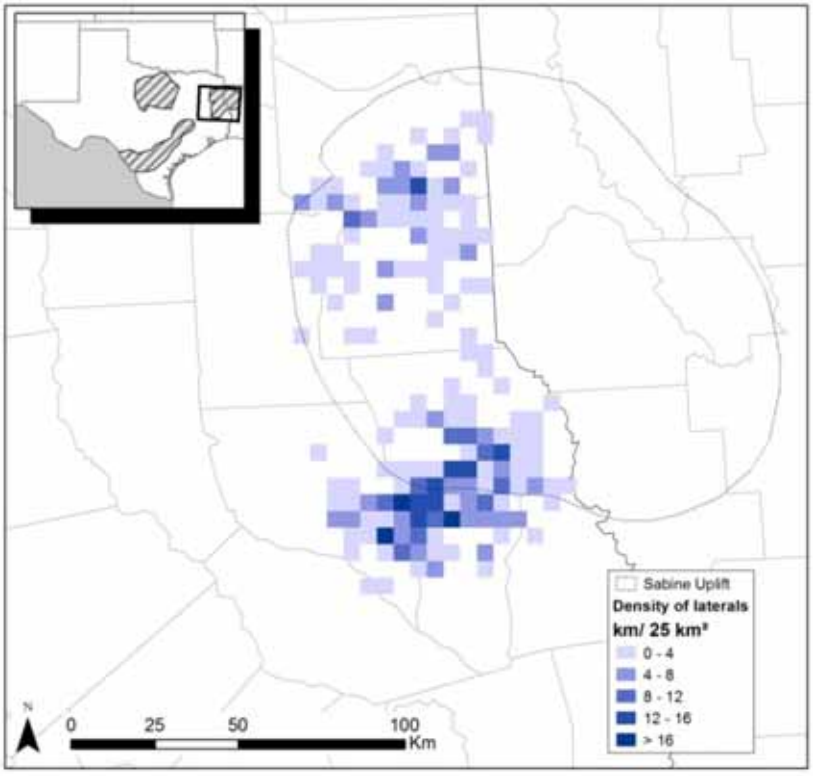
(b)

Figure 15. TX-Haynesville Shale horizontal water use intensity as a function of (a) depth; and (b) formation thickness.

TX-Haynesville Shale:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 16. TX-Haynesville Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

TX-Haynesville Shale:

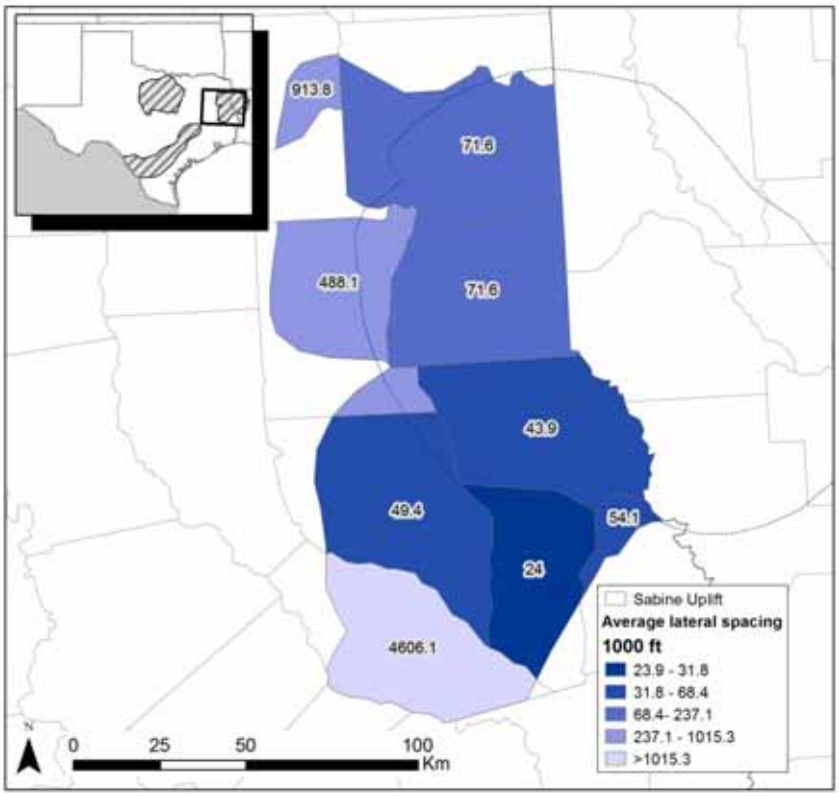
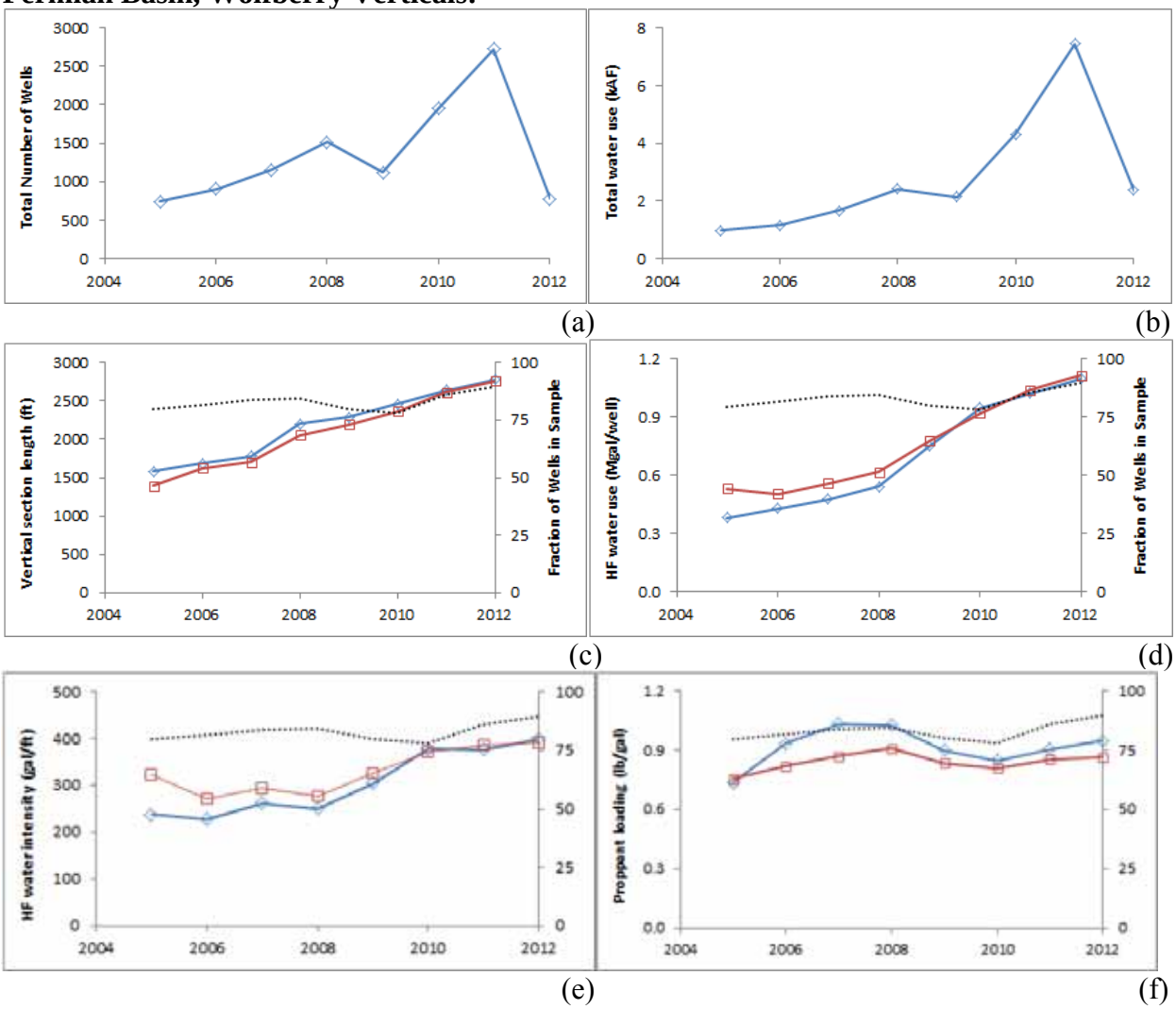


Figure 17. TX-Haynesville Shale county-level average lateral spacing.

Table 5. TX-Haynesville Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
San Augustine	0.137	23.97
Shelby	0.074	44.24
Nacogdoches	0.065	50.78
Sabine	0.061	54.11
Panola	0.046	72.03
Harrison	0.045	72.84

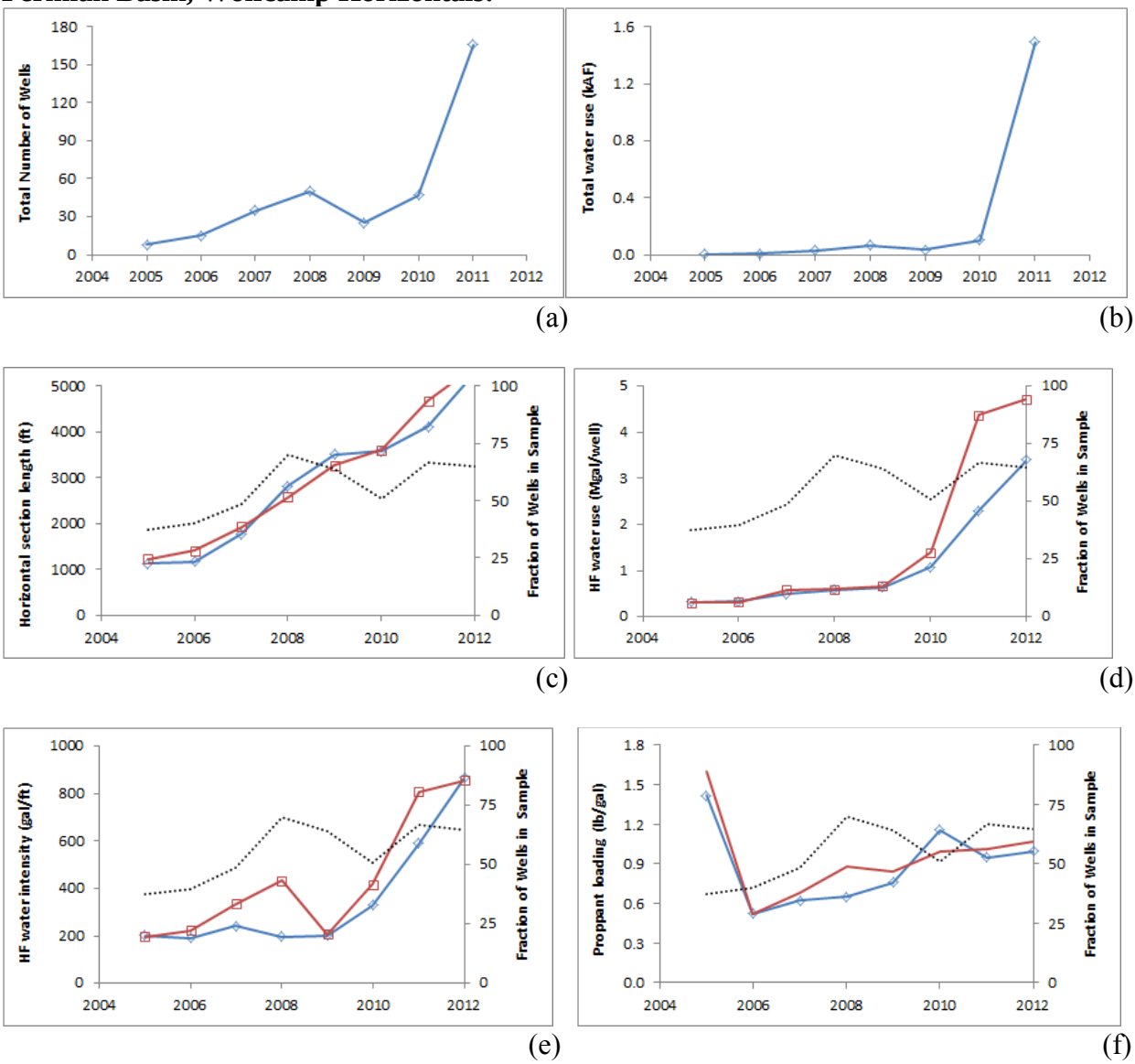
Permian Basin, Wolfberry Verticals:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 18. Wolfberry verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

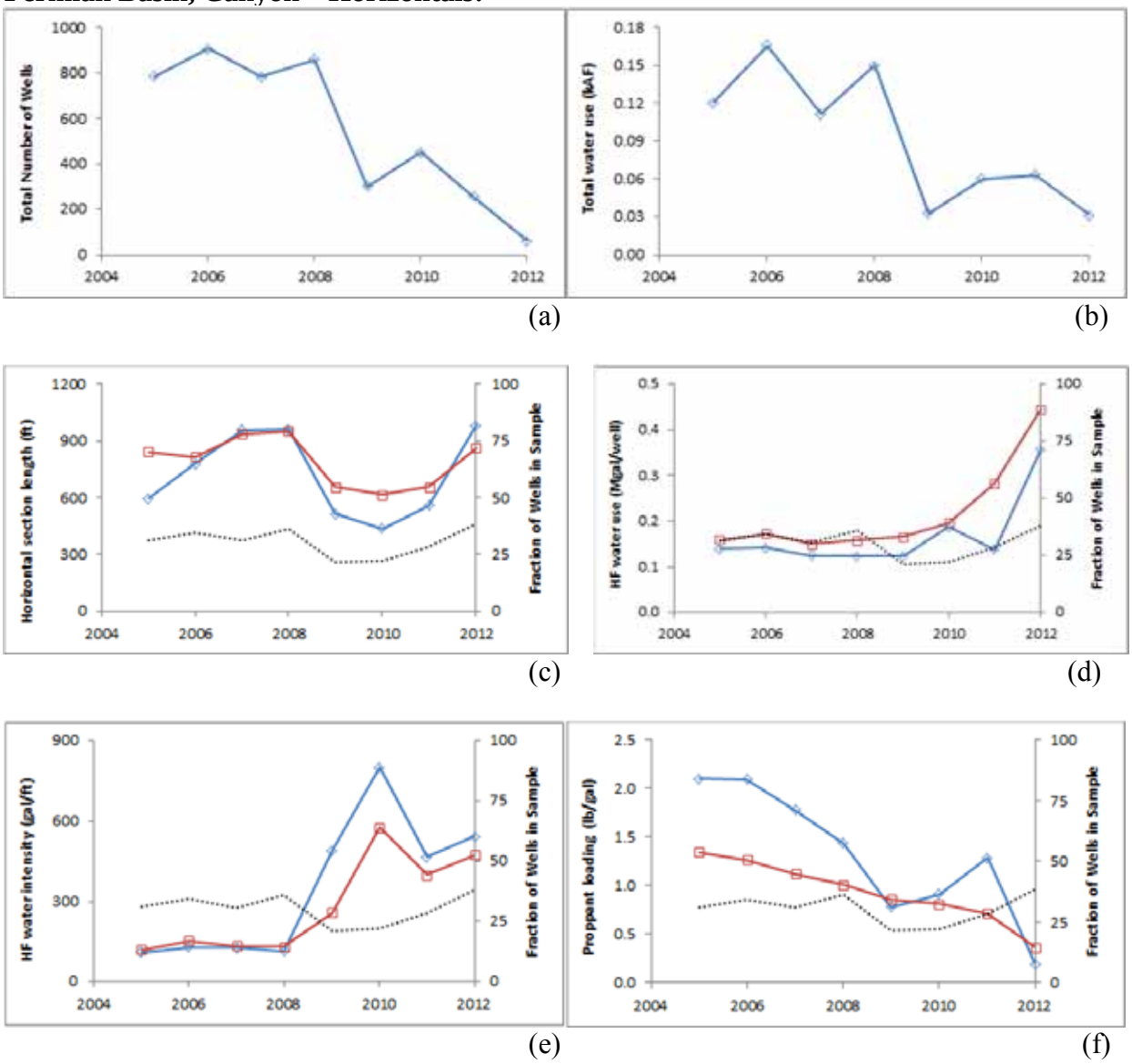
Permian Basin, Wolfcamp Horizontals:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 19. Wolfcamp horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

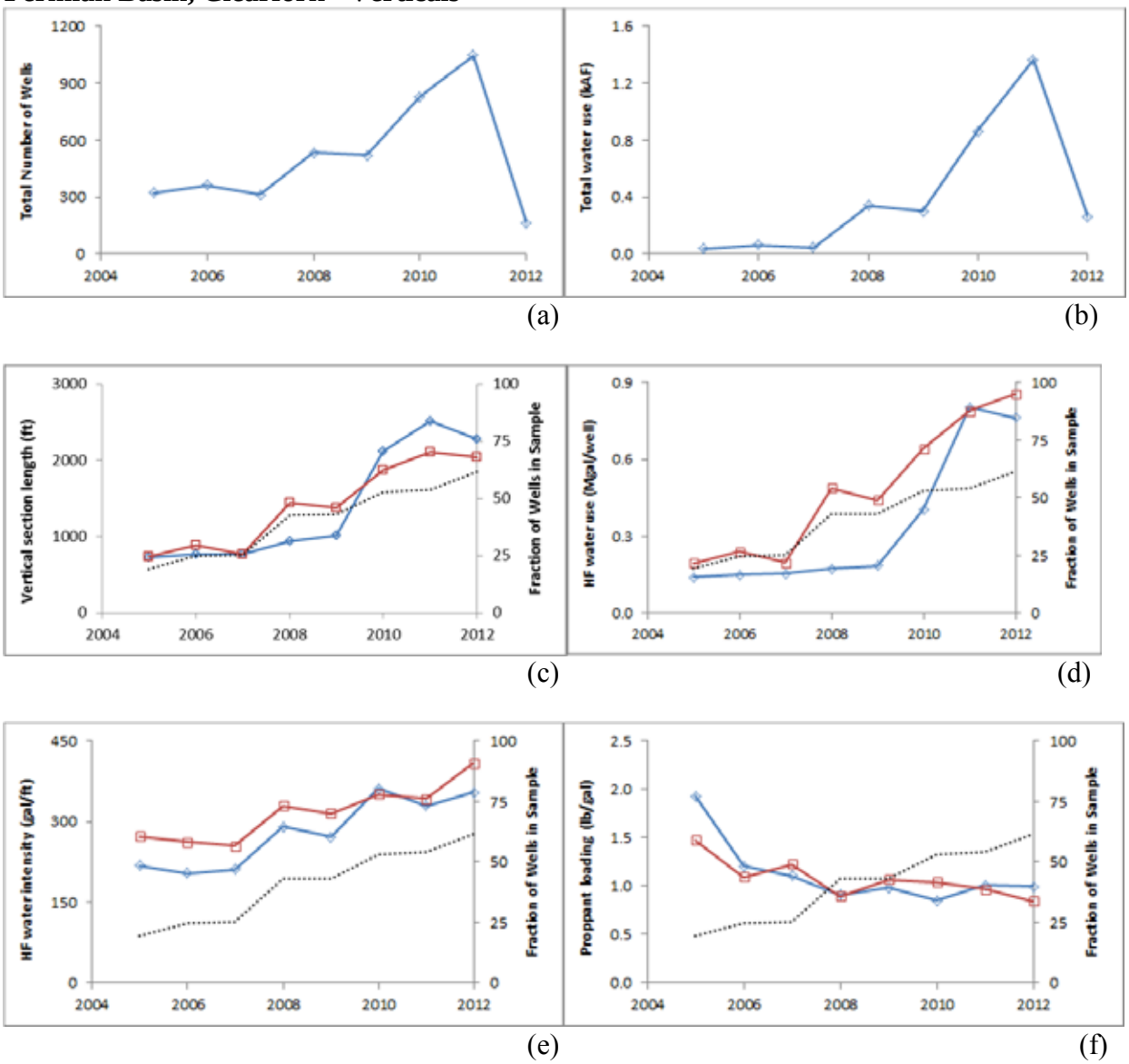
Permian Basin, Canyon – Horizontals:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 20. Canyon Sand horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

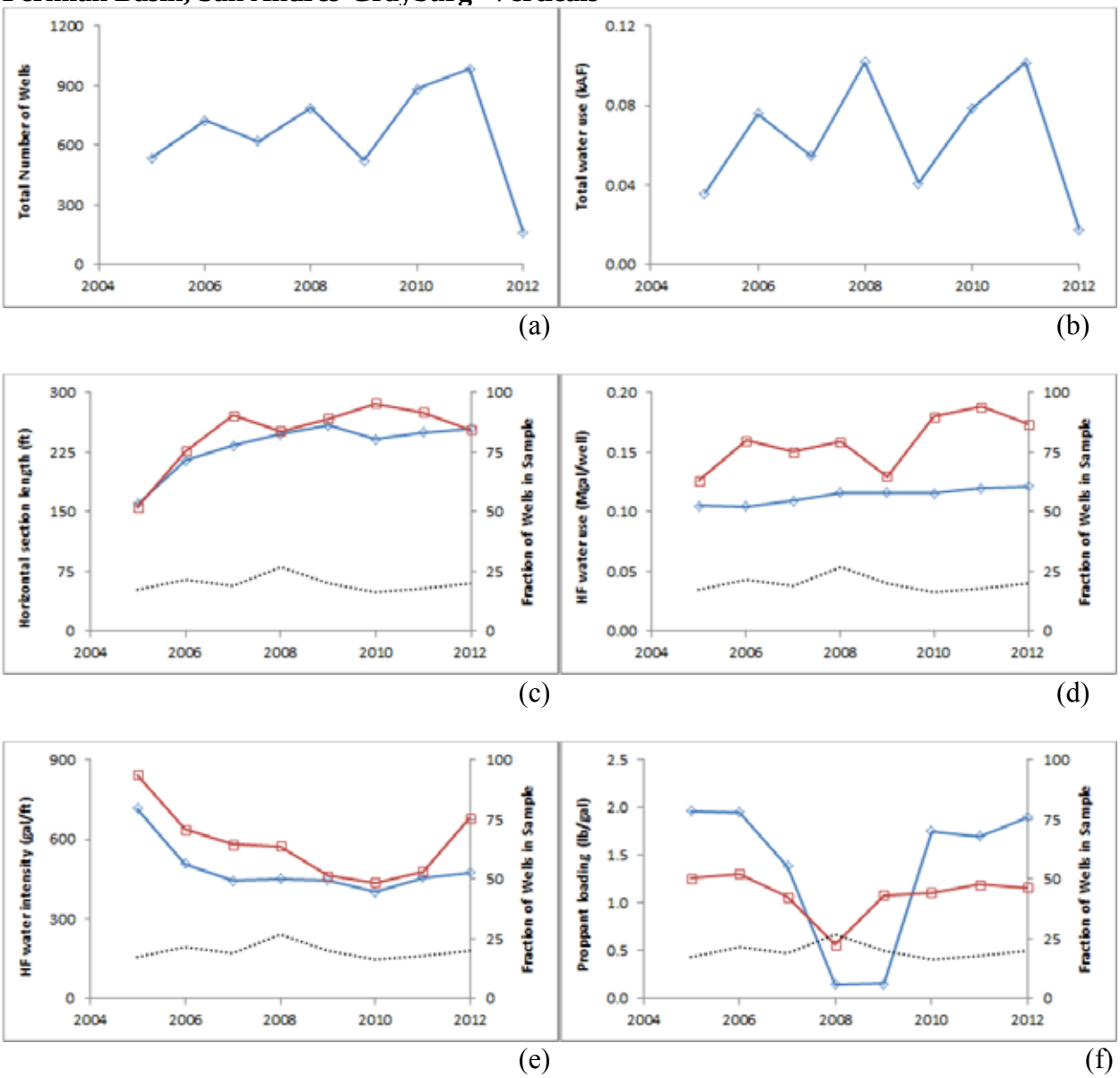
Permian Basin, Clearfork - Verticals



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 21. Clearfork verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

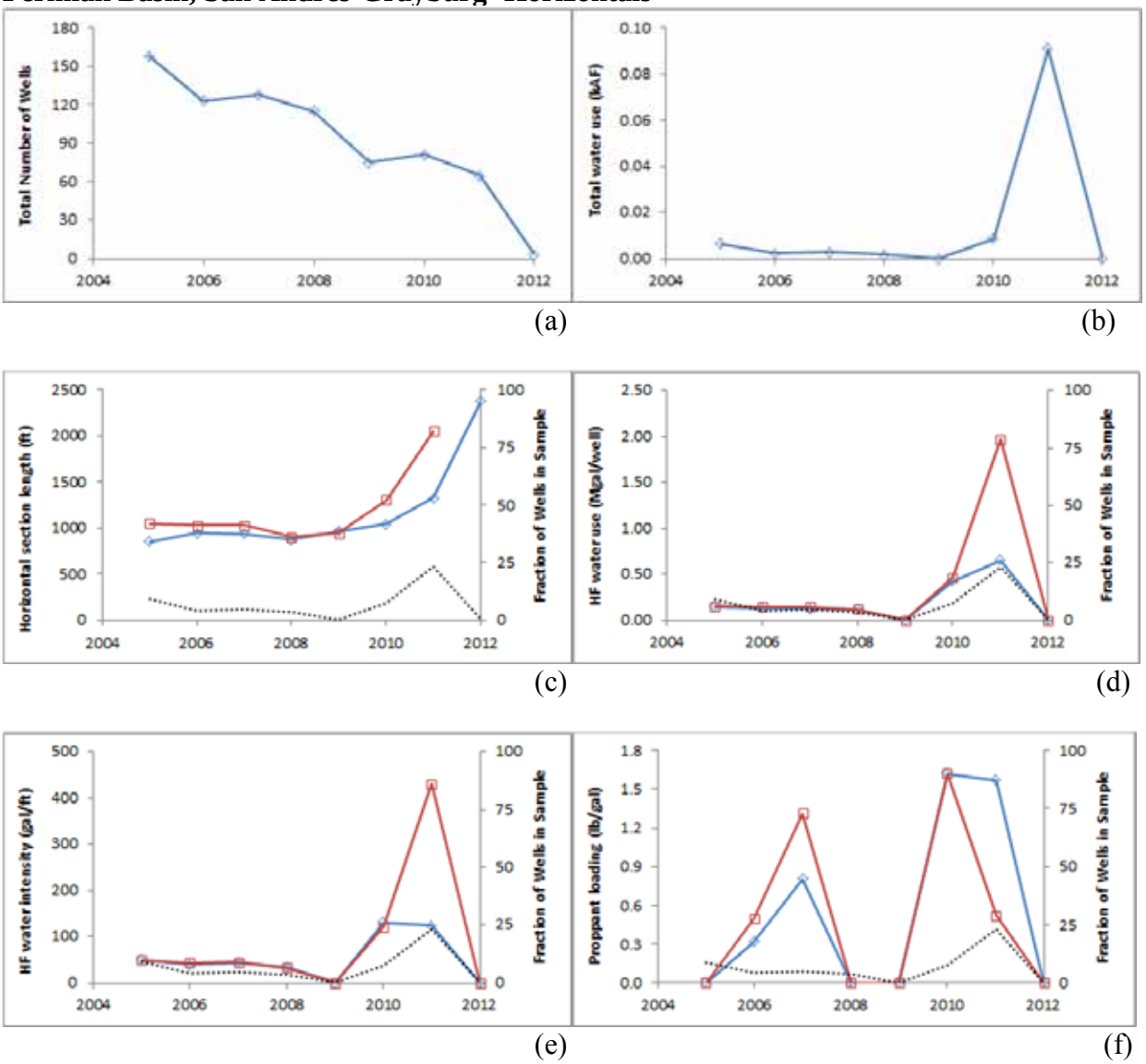
Permian Basin, San Andres-Grayburg -Verticals



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 22. San Andres-Grayburg verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

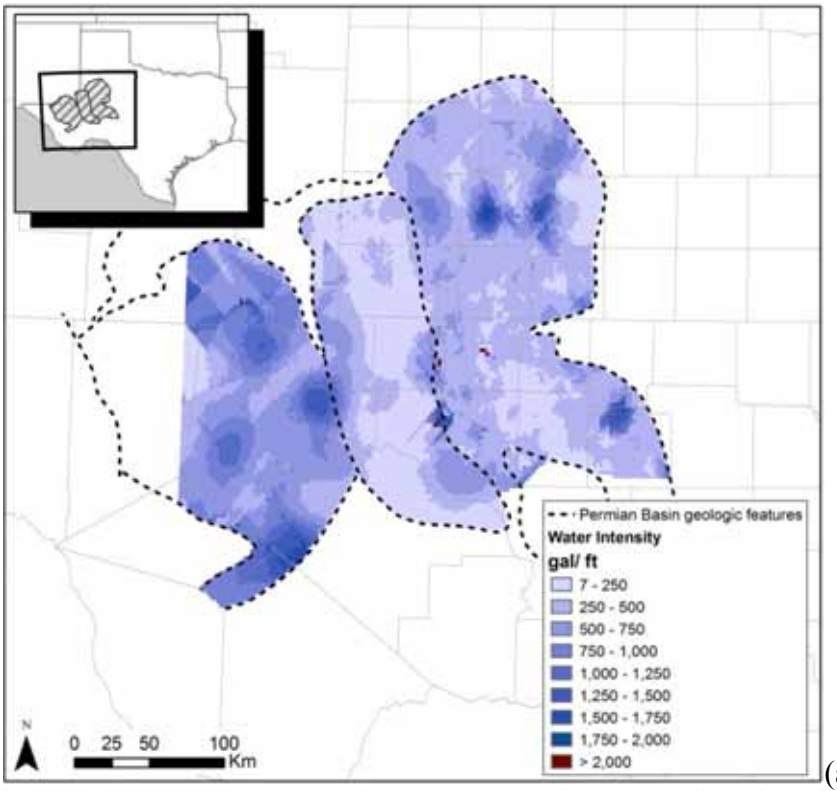
Permian Basin, San Andres-Grayburg -Horizontals



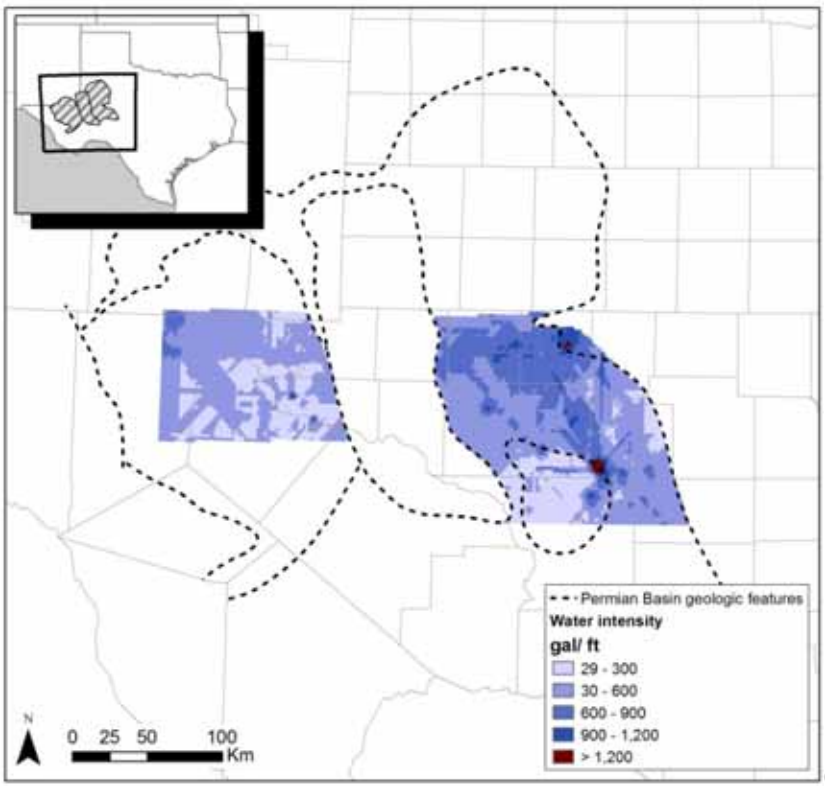
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 23. San Andres-Grayburg horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Permian Basin:



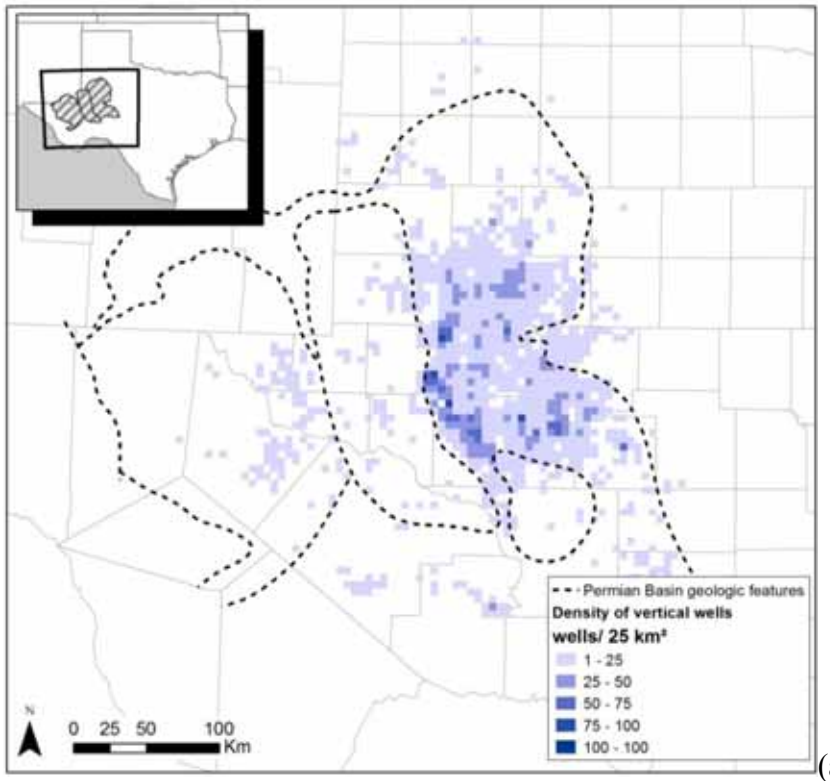
(a)



(b)

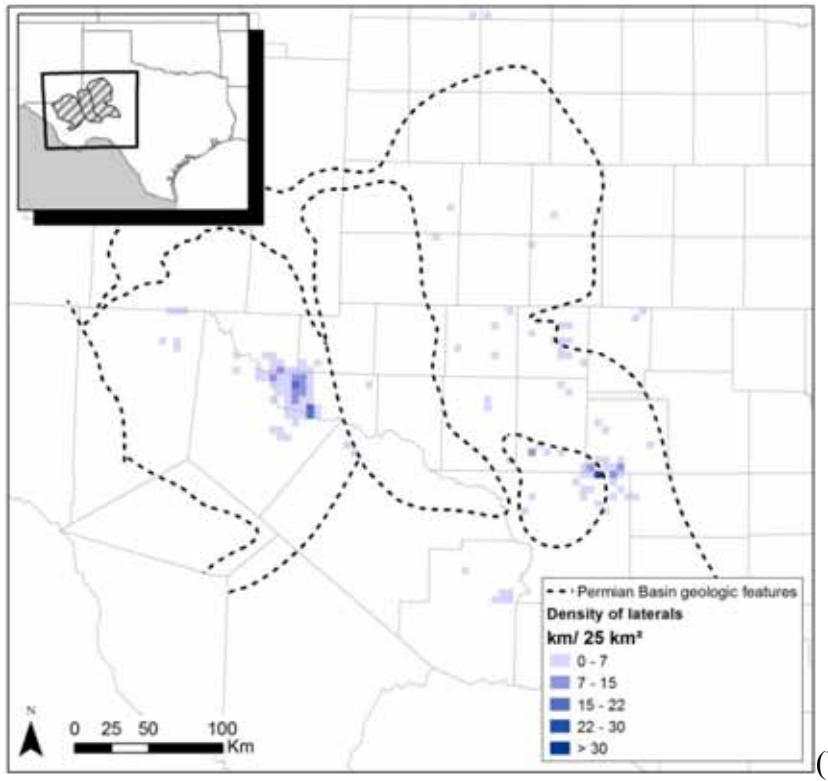
Figure 24. Permian Basin spatial distribution of water intensity for (a) vertical and (b) horizontal wells.

Permian Basin:



(a)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres



(b)

Figure 25. Permian Basin spatial distribution of (a) vertical well density and (b) density of lateral (cumulative length per area) for horizontal wells.

Permian Basin

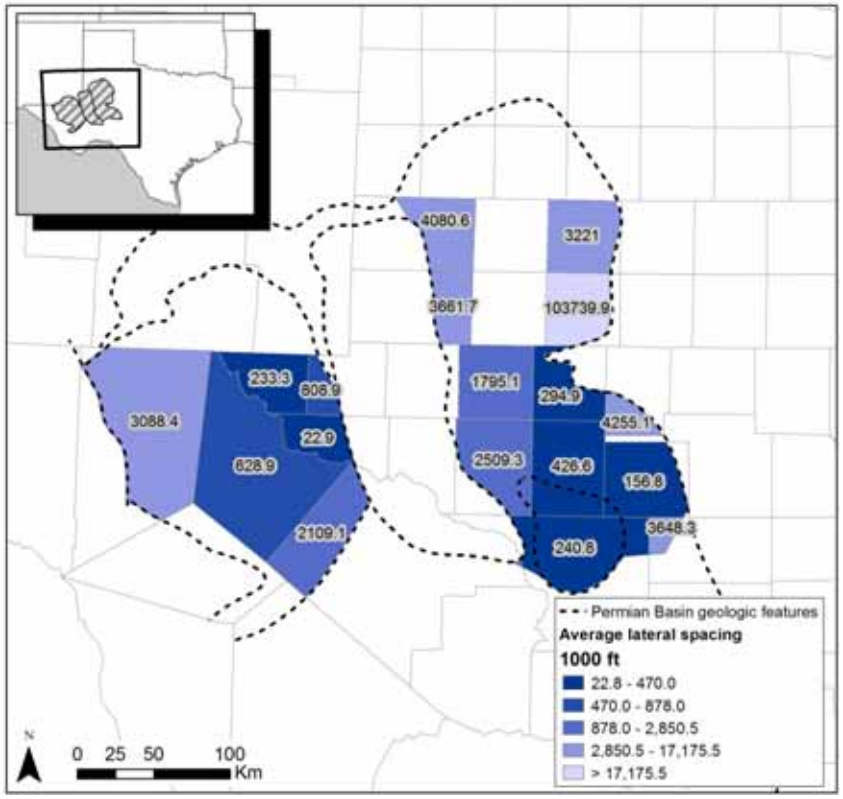
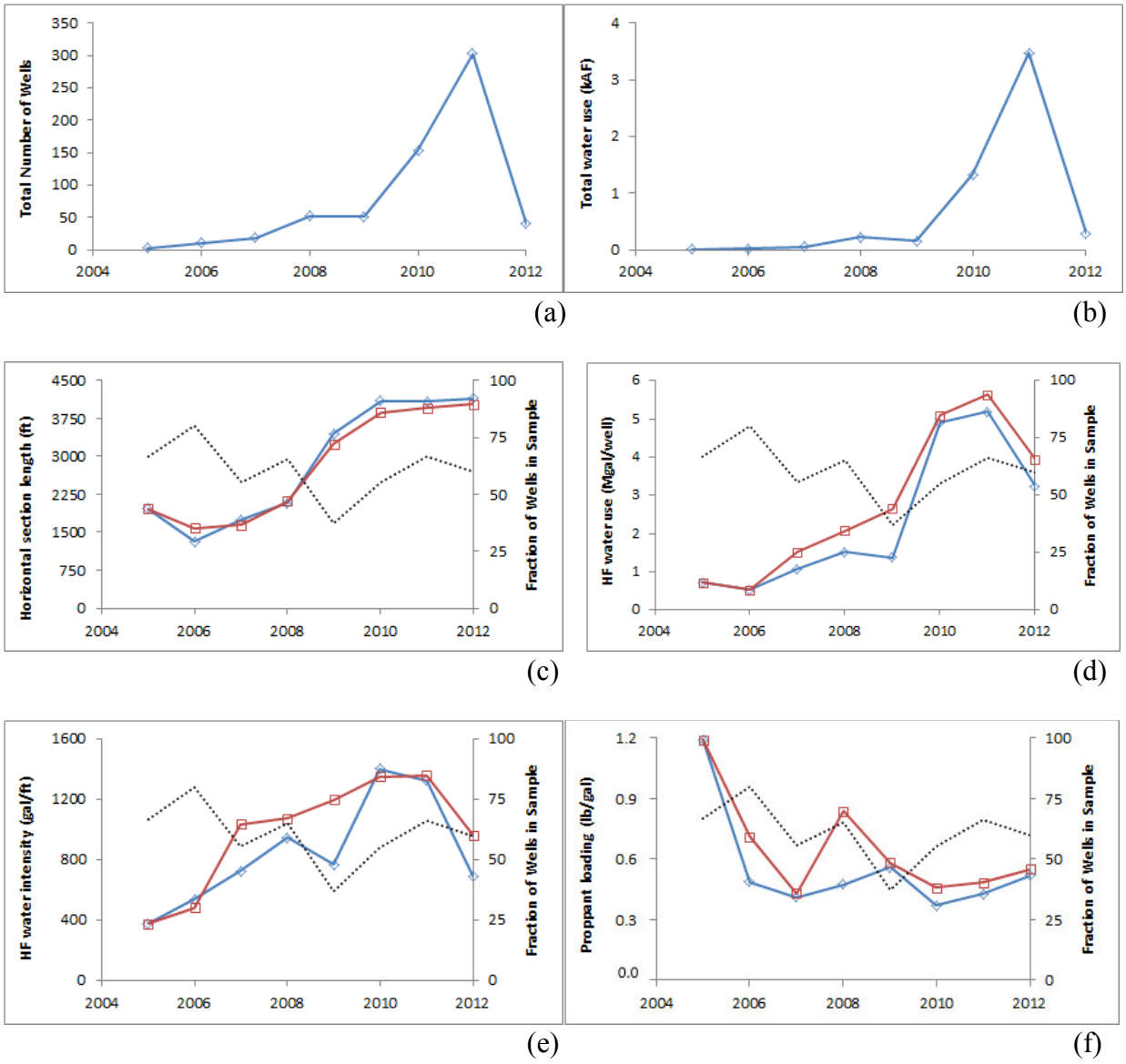


Figure 26. Permian Basin county-level average lateral spacing

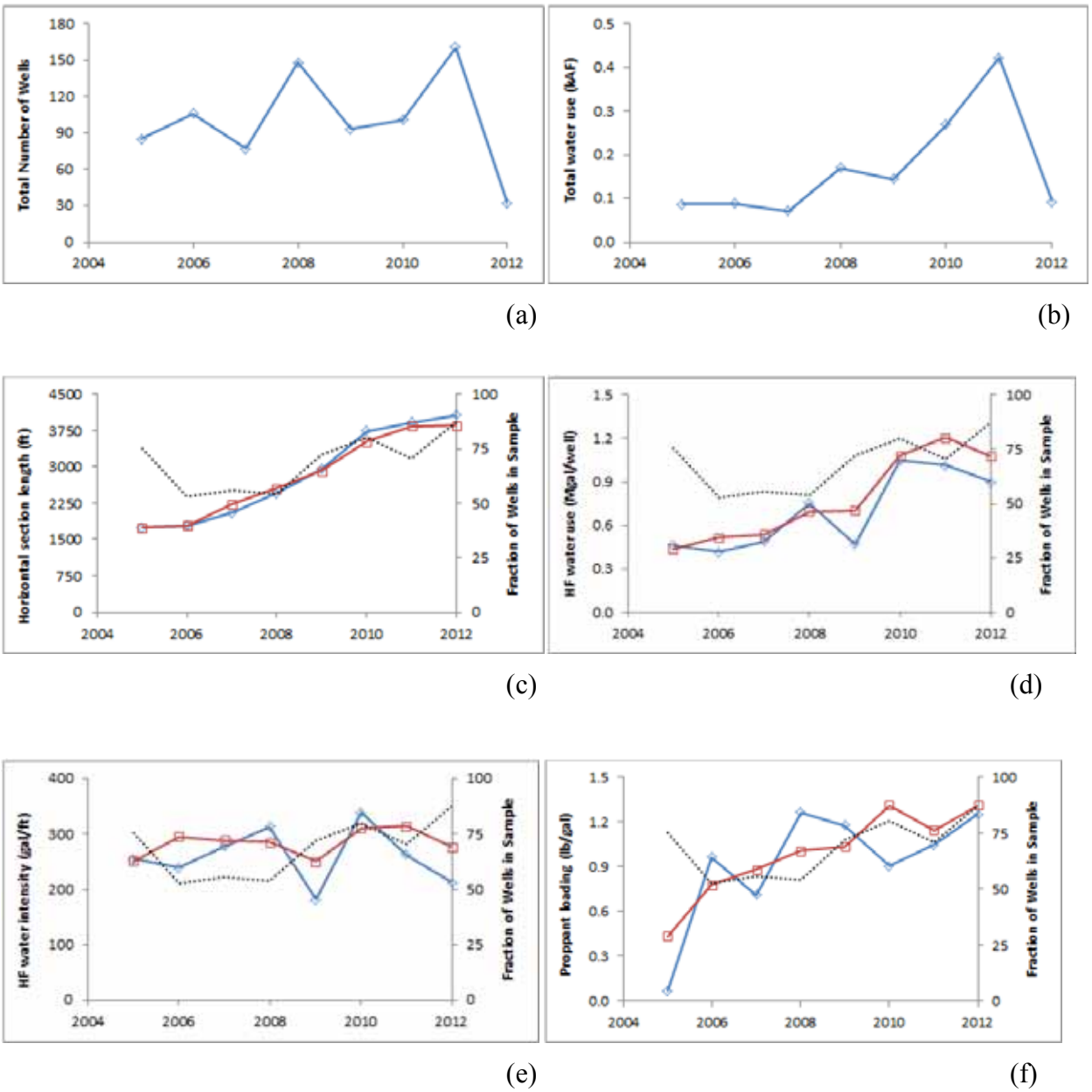
Anadarko Basin: Granite Wash Horizontals:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 27. Granite Wash horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

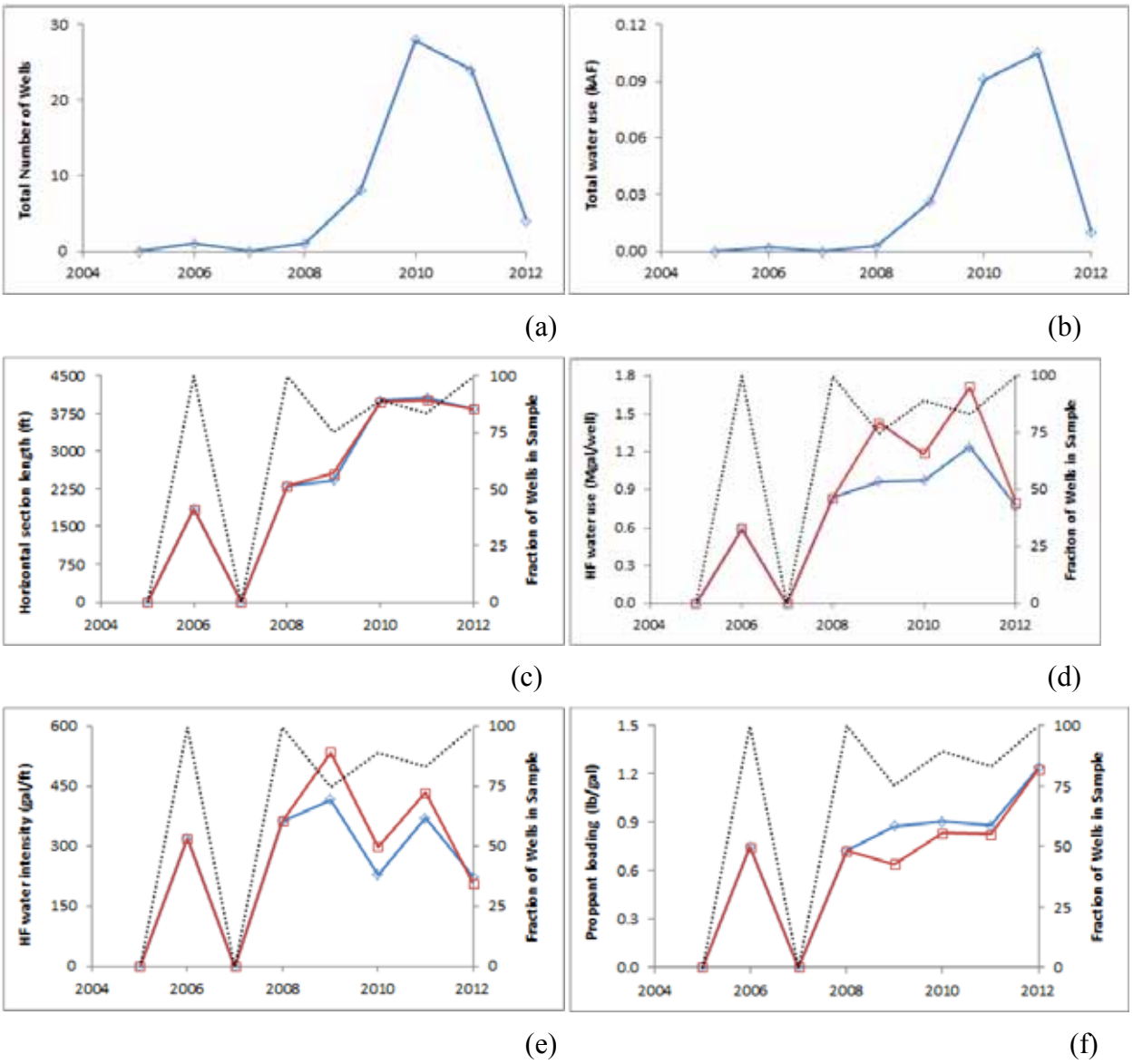
Anadarko Basin: Cleveland Horizontals:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 28. Cleveland horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Anadarko Basin: Marmaton Horizontals:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 29. Marmaton horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Anadarko Basin: Granite Wash Horizontals:

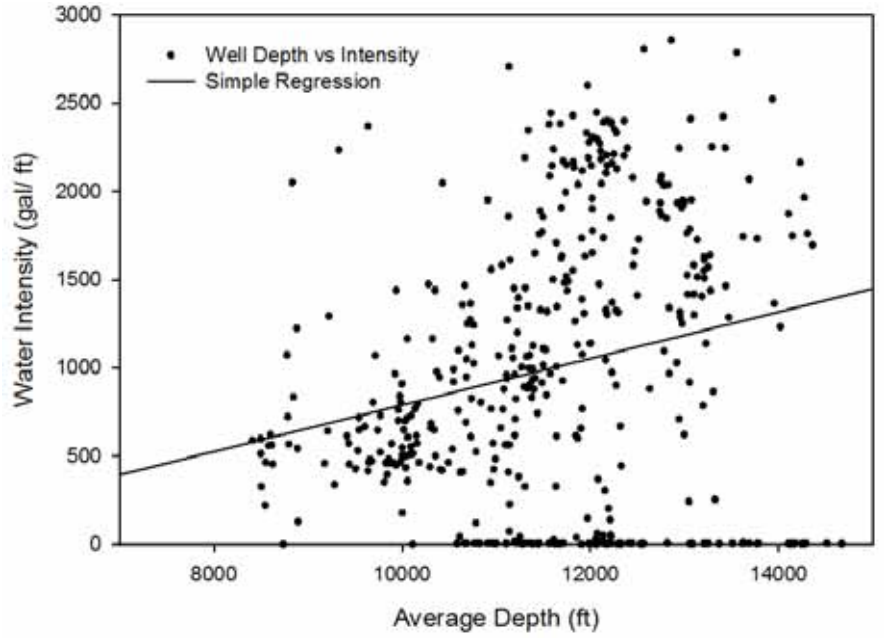


Figure 30. Granite Wash horizontal water use intensity as a function of depth.

Anadarko Basin: Cleveland Horizontals:

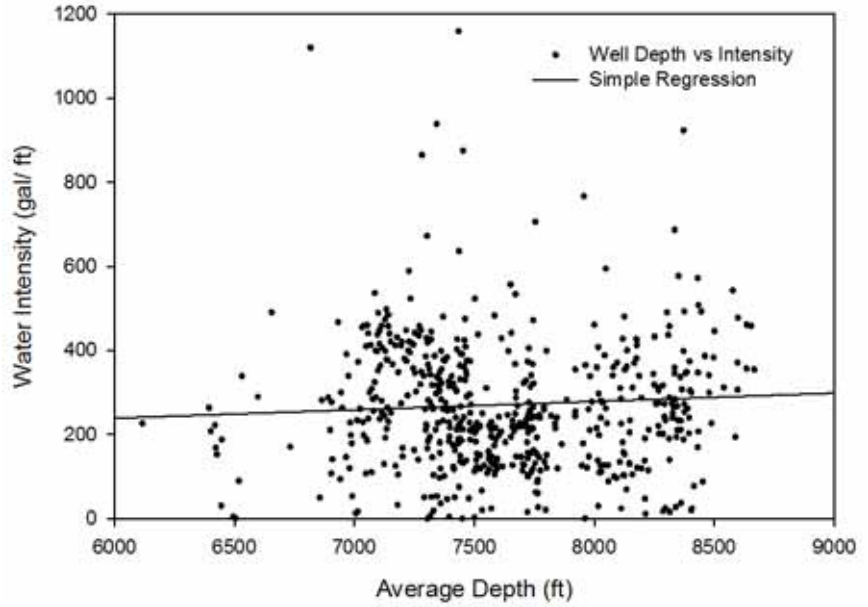
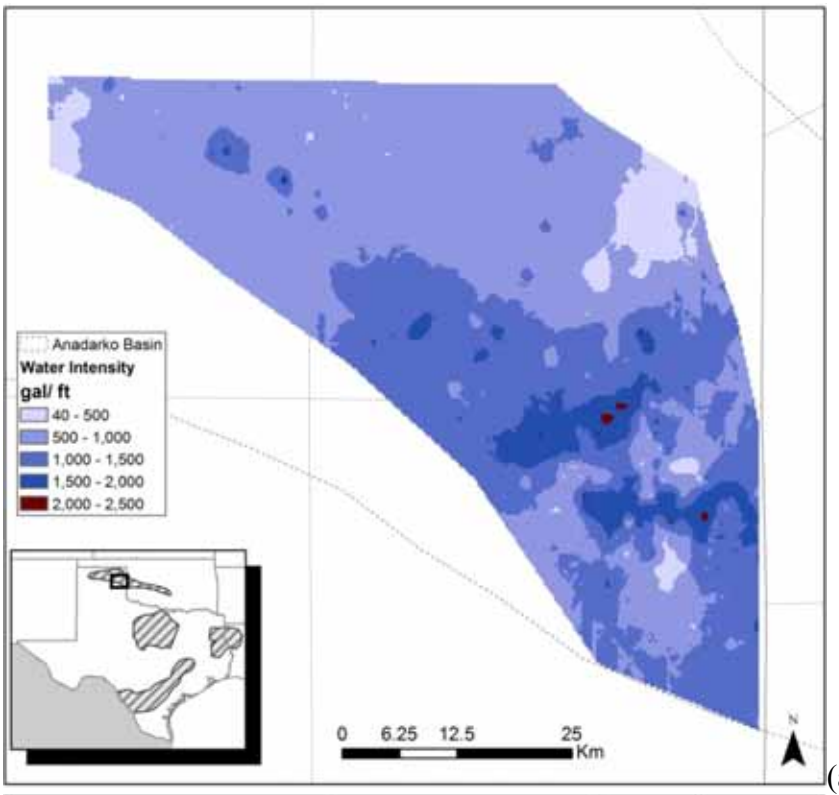
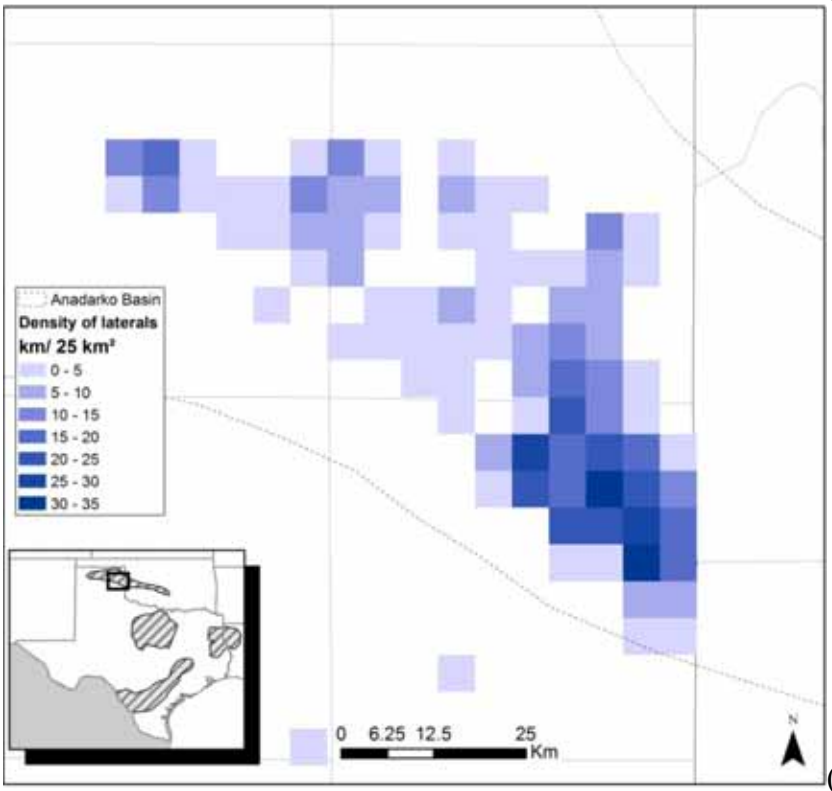


Figure 31. Cleveland horizontal water use intensity as a function of depth.

Anadarko Basin: Granite Wash Horizontals:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 32. Granite Wash spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Anadarko Basin: Granite Wash Horizontals:

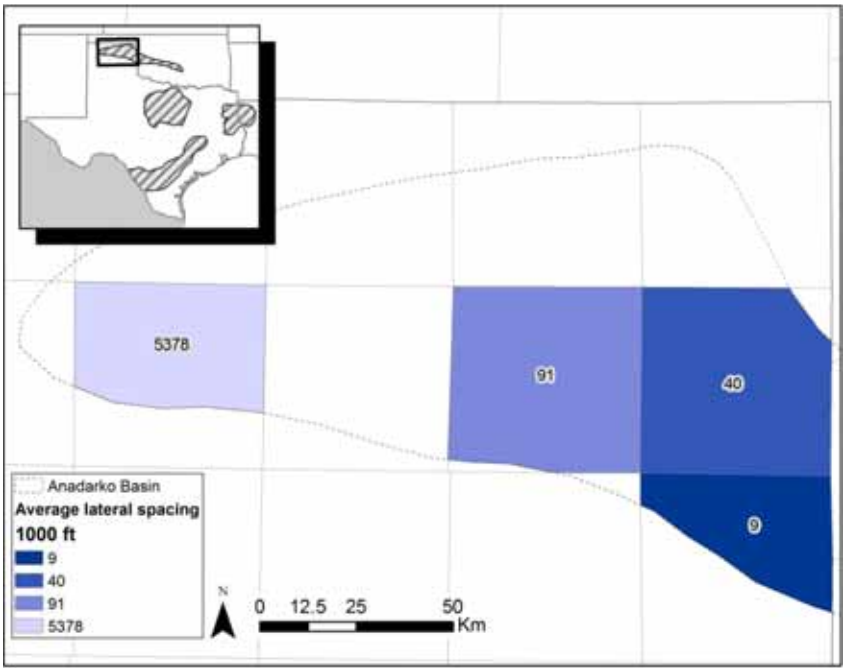
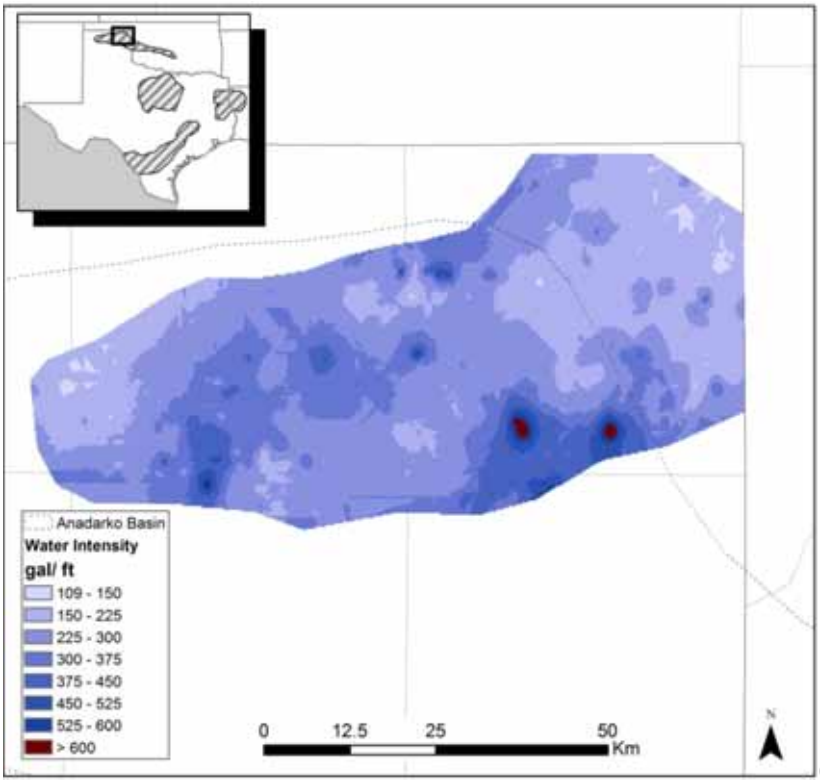


Figure 33. Granite Wash horizontals county-level average lateral spacing

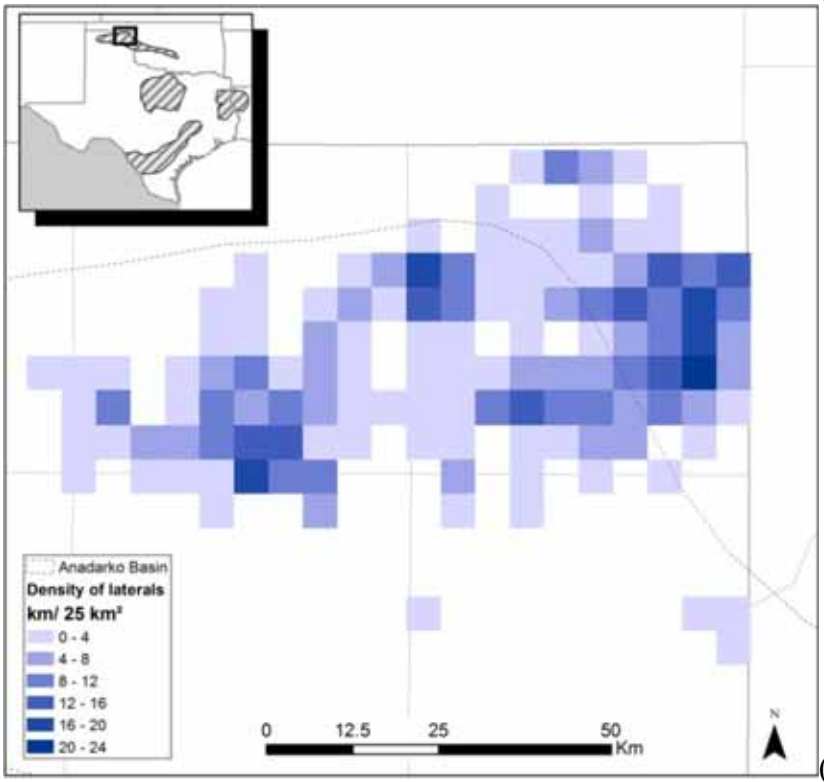
Table 6. Granite Wash county-level average lateral spacing for top producing counties

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Wheeler	0.351	9.34
Hemphill	0.082	39.74
Roberts	0.036	90.54

Anadarko Basin: Cleveland Horizontals:



(a)

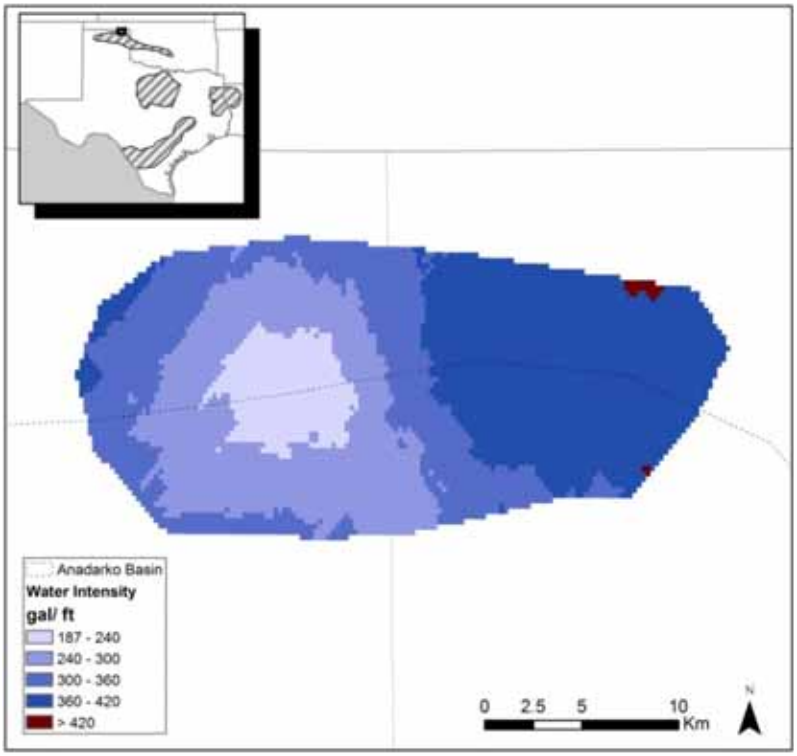


(b)

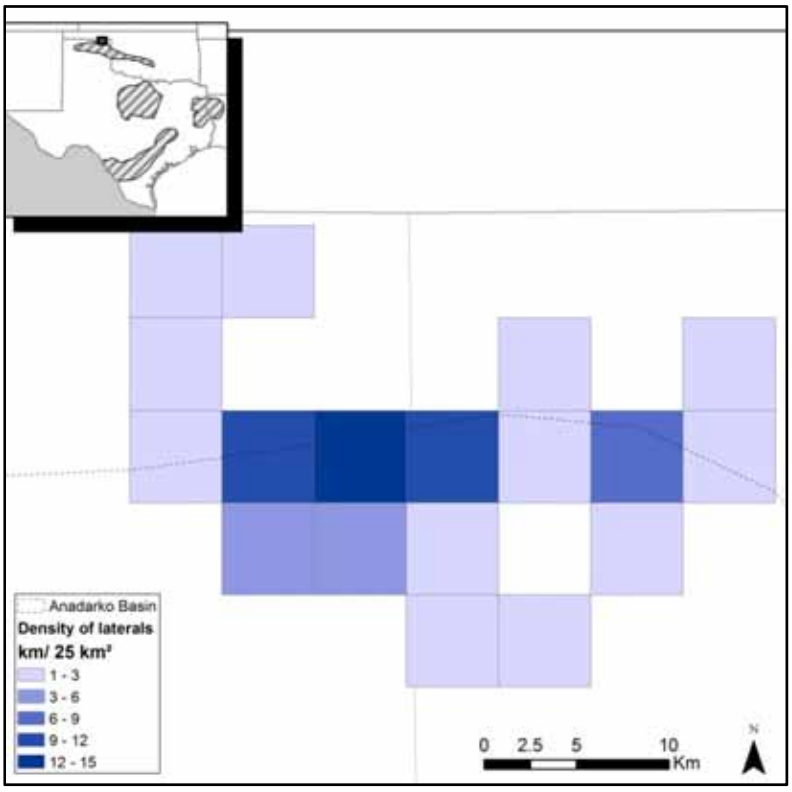
Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 34. Cleveland spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Anadarko Basin: Marmaton Horizontals:



(a)

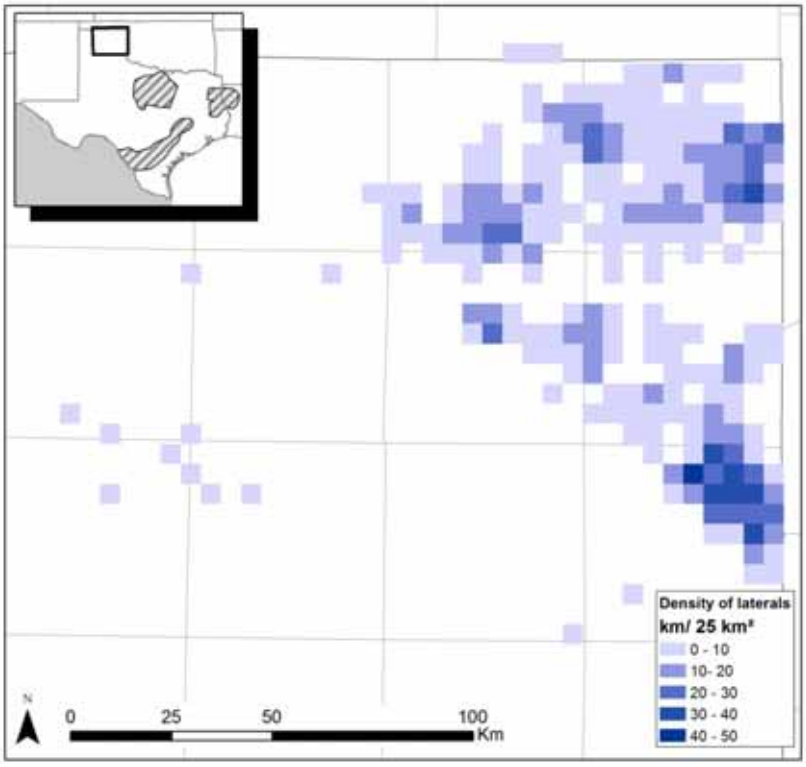


(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

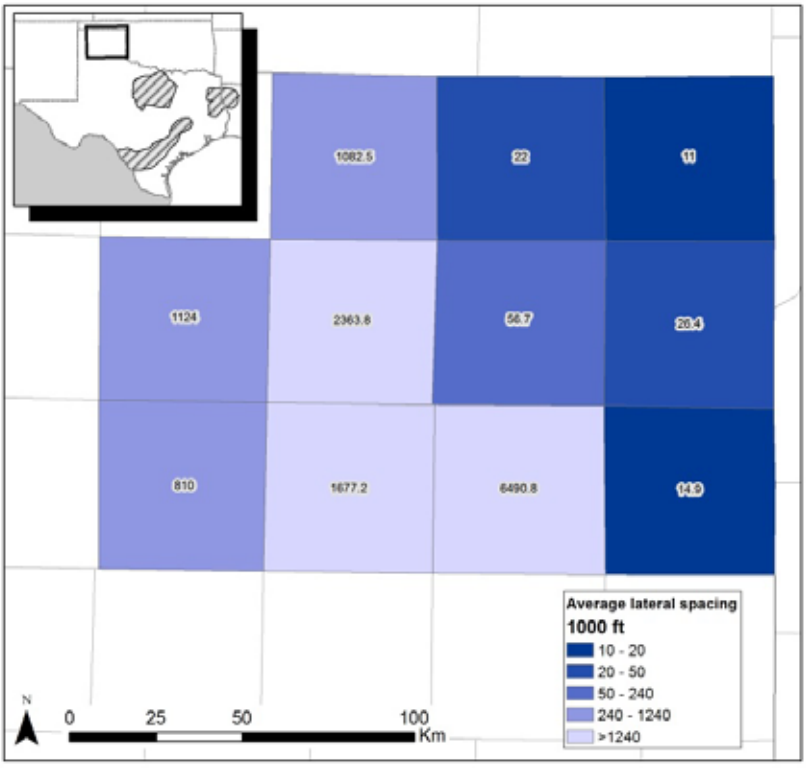
Figure 35. Marmaton spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Anadarko Basin: Horizontals:



(a)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres



(b)

Figure 36. Anadarko spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

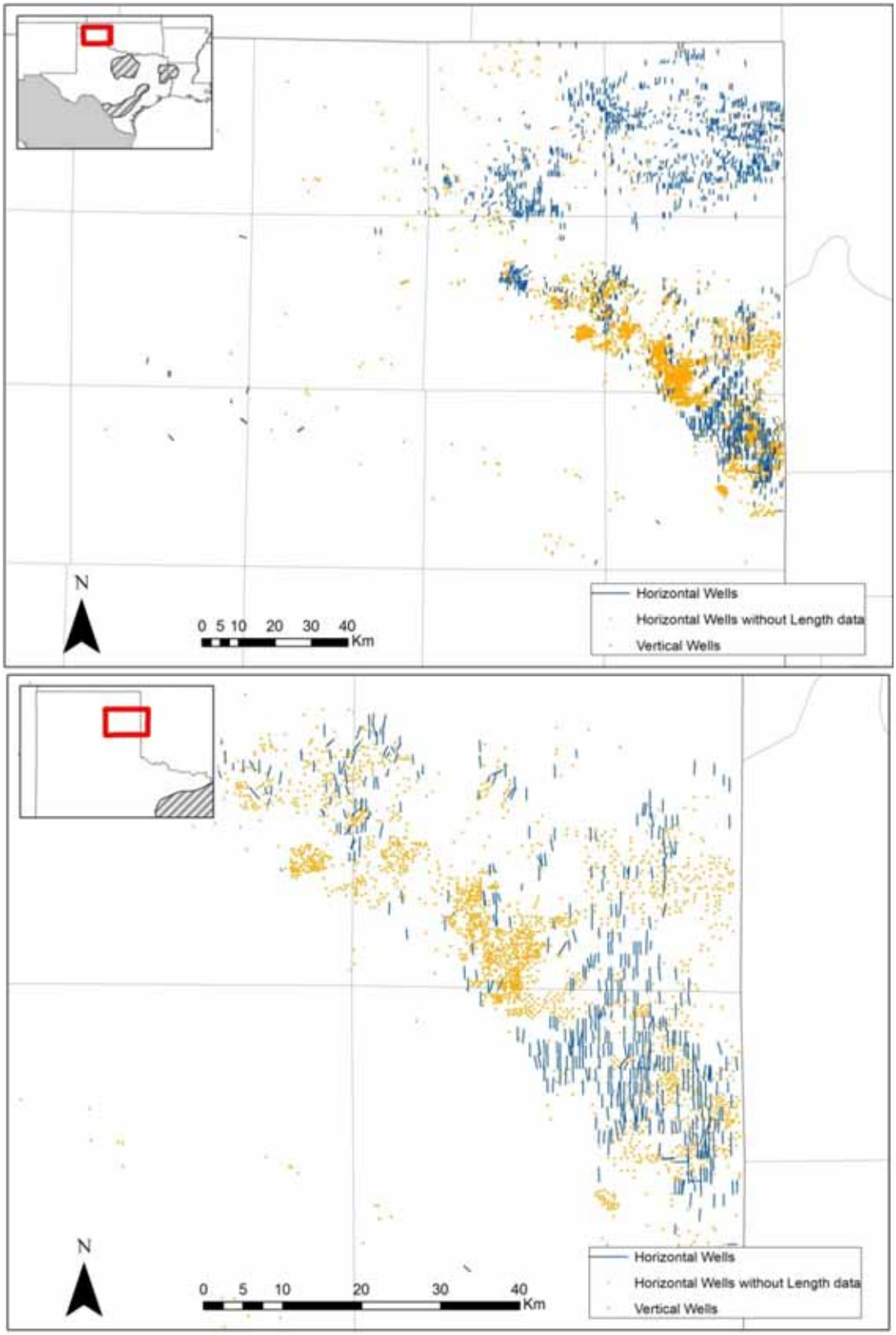
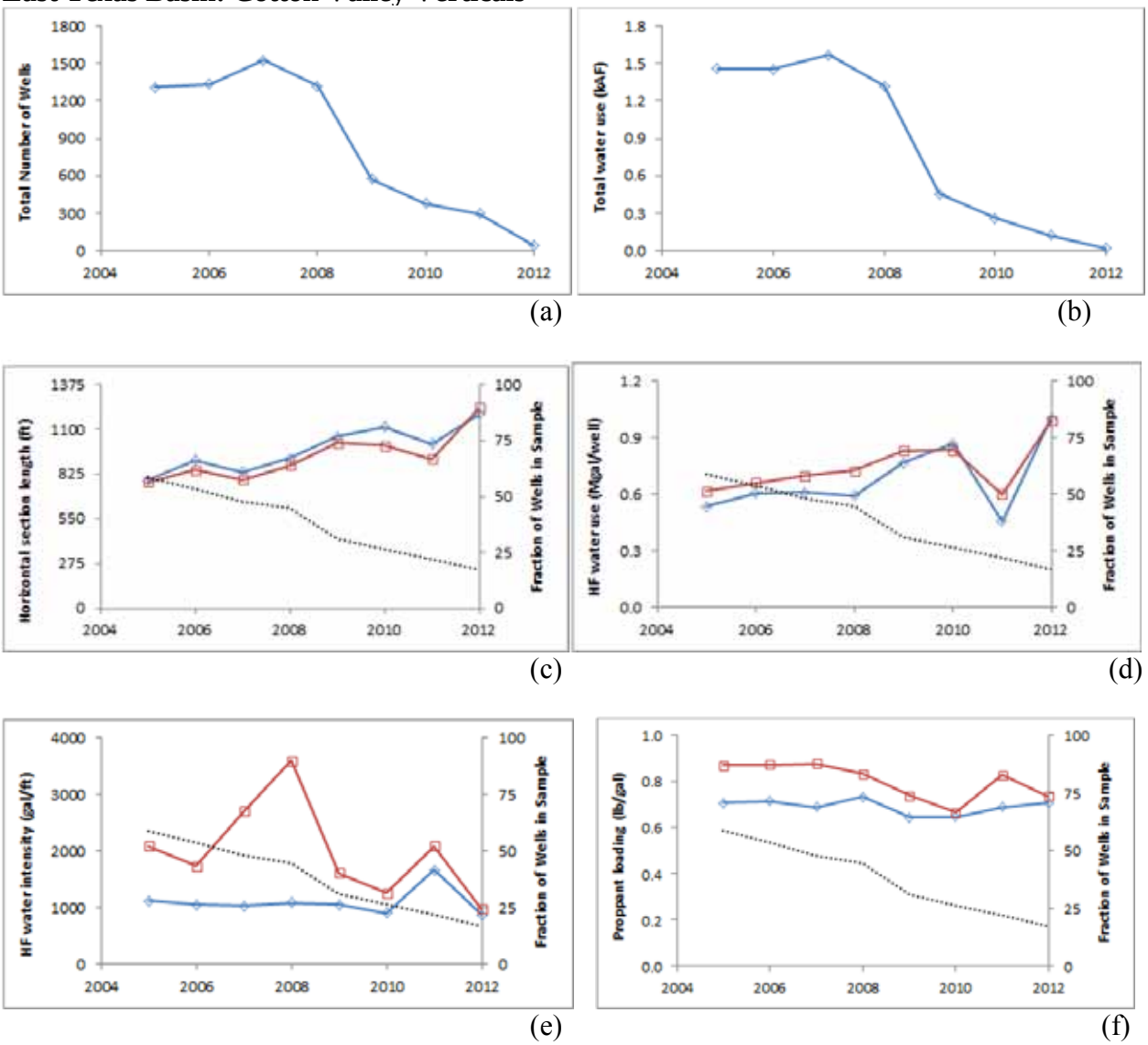


Figure 37. Map view of wells' lateral expression and vertical well location in the Anadarko Basin.

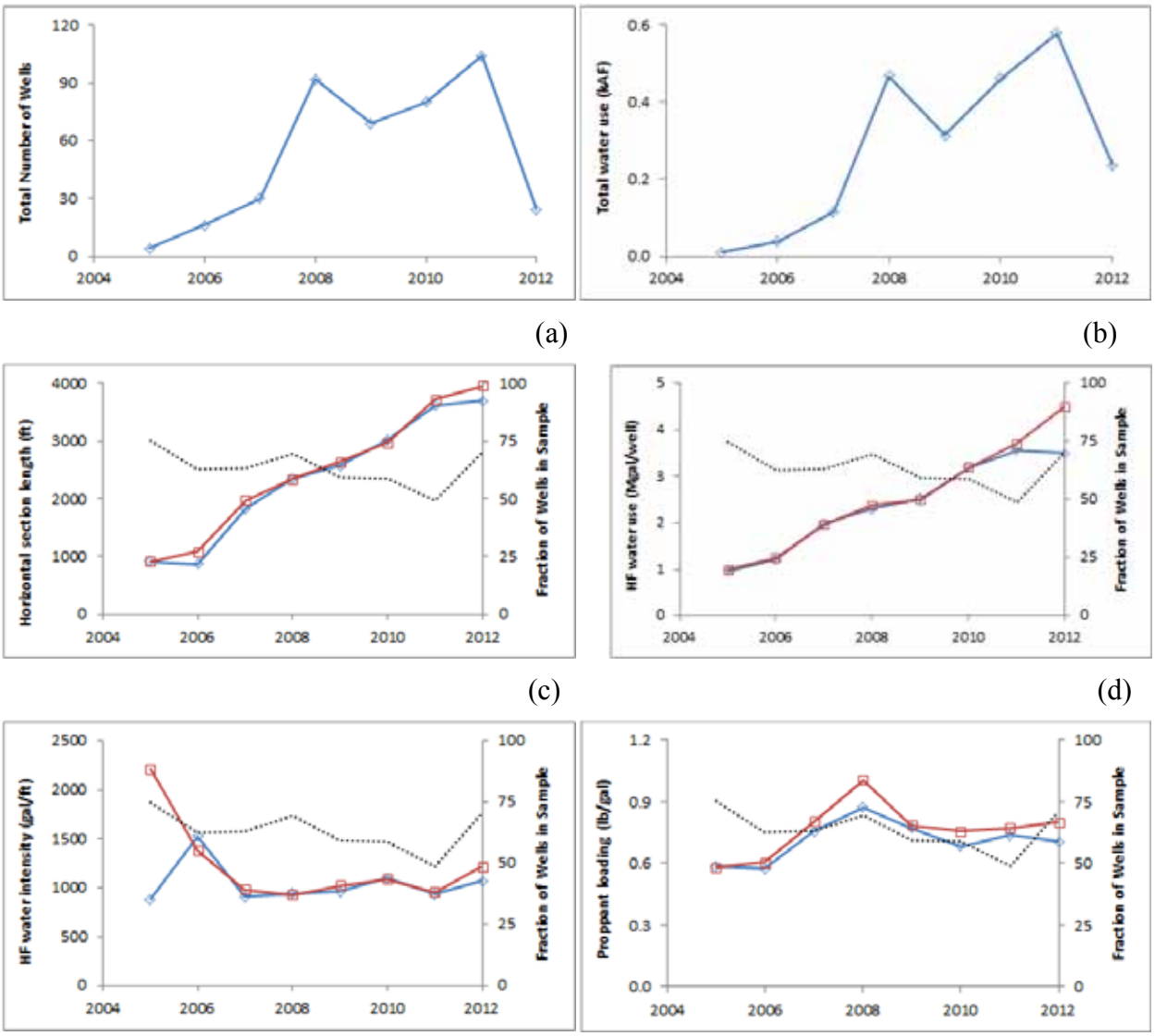
East Texas Basin: Cotton Valley Verticals



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 38. Cotton Valley verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

East Texas Basin: Cotton Valley Horizontals



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 39. Cotton Valley horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

East Texas Basin: Cotton Valley

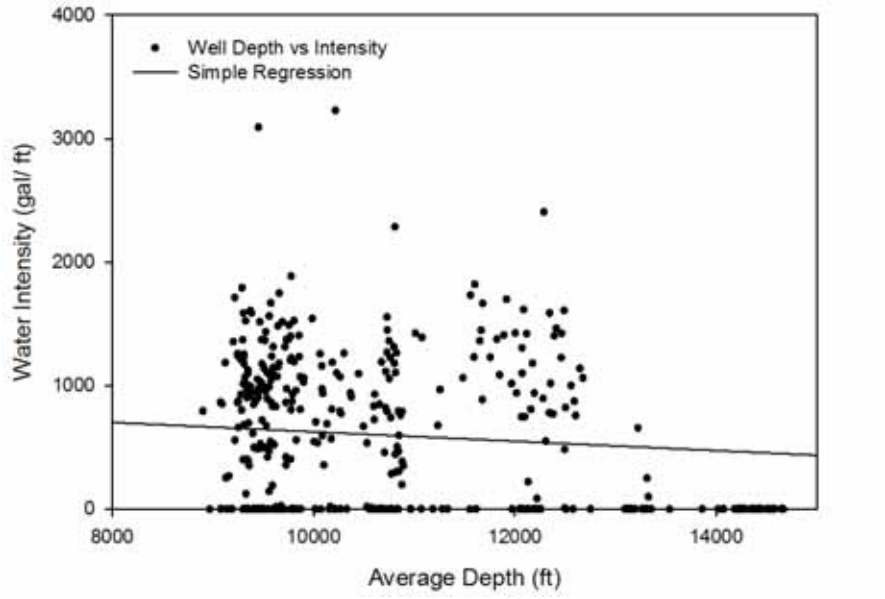
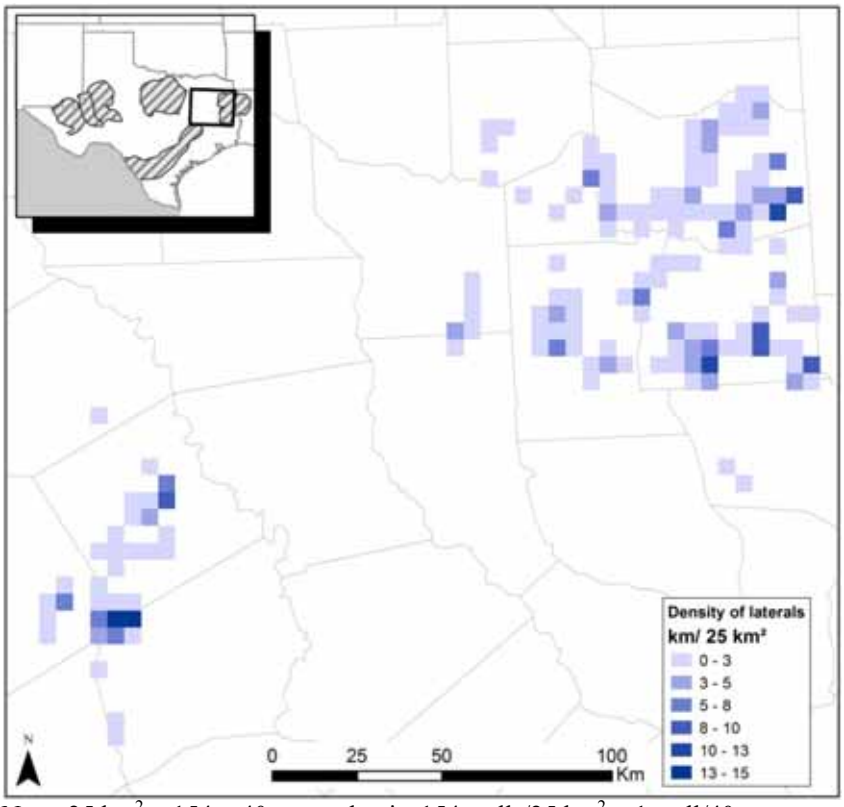


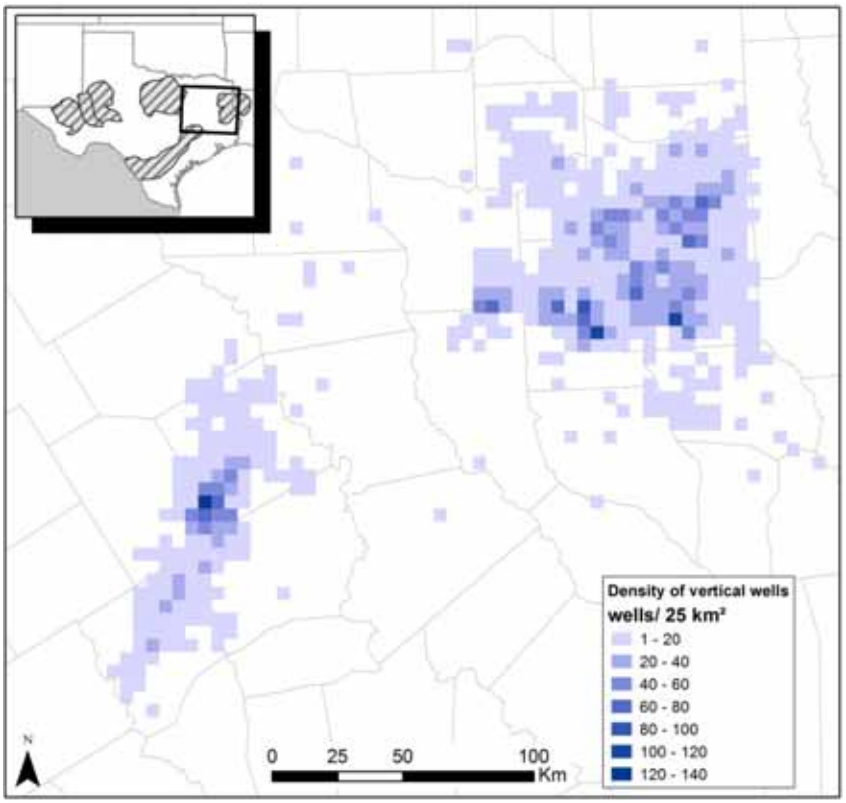
Figure 40. Cotton Valley horizontal water use intensity as a function of depth.



Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 41. Cotton Valley spatial distribution of density of lateral (cumulative length per area).

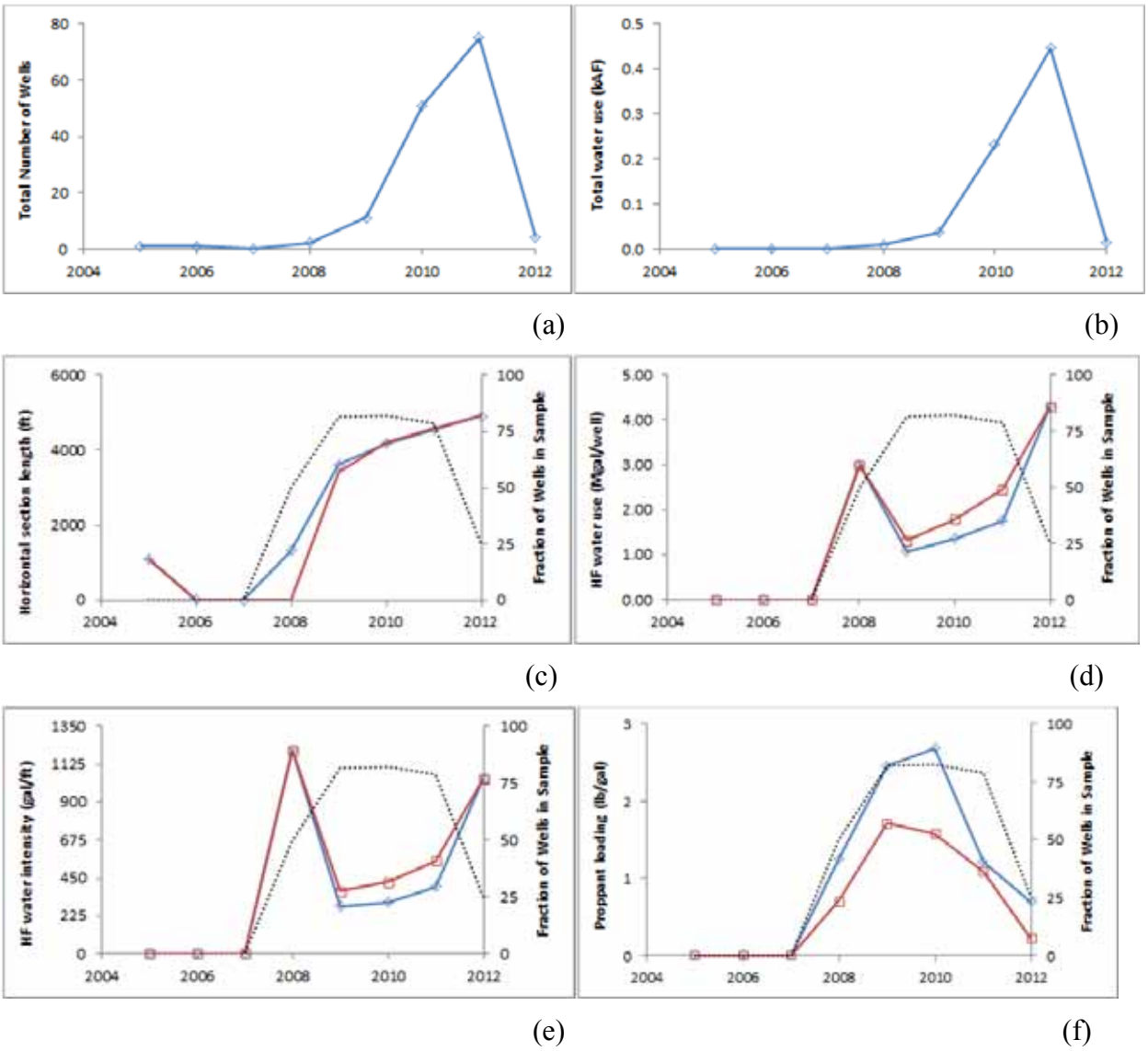
East Texas Basin: Cotton Valley



Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres
Note: Cotton Valley wells drilled before 2005 are not included (see Nicot et al., 2011 for details).

Figure 42. Cotton Valley spatial distribution of density of vertical wells (years 2005-2011).

Gulf Coast Basin, Olmos - Horizontal



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 43. Olmos horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

III-2. Current Water Consumption and Sources

III-2-1 Information about Recycling/Reuse and Brackish Water Use

We collected information about recycling/reuse and brackish water use gathered during discussions with operators (Table 7). The amount of fresh water used is quite unequal across the different plays as a function of the local conditions. It can be as low as 20% in Far-West Texas or nearly 100% in East Texas. Collecting a sufficient amount of information concerning recycling/reuse and brackish water use is an improvement over the 2011 report which overall underestimated it. Reuse is limited by the amount of flow back that varies across plays. We could not document volumes of water recycled from wastewater treatment plants, but the TCEQ lists ~30 municipal and industrial facilities located in the Barnett Shale and Eagle Ford Shale plays that provide water to the industry (Figure 44). Groundwater/surface water could be extremely variable within a single play, but water data also reflect local conditions (Table 8): heavy surface water use towards the eastern part of the state and reliance on groundwater (sometimes brackish) elsewhere. The following short paragraphs discuss recycling/reuse and brackish water use and GS/SW split in major plays/regions.

Barnett Shale: For the most part, operators use fresh surface water in this play (estimated at 80% of "new" water). This is a change from the 50%+ groundwater use estimated in 2006 in Bené et al. (2007) and Nicot and Potter (2007). Some operators use brackish water, particularly in the combo play and on the western edges of the play. Some also use outfall from wastewater treatment plants. Overall, little recycling/reuse and brackish water use is currently occurring in this play as compared to other plays further west or south.

Eagle Ford Shale: Operators rely mostly on groundwater (estimated at 90% of "new" water) and there is a significant amount of brackish water being used (currently estimated at 20% but variable among operators). Several aquifers are brackish in the footprint of the play: the Gulf Coast aquifers and the Wilcox aquifers as well as the downdip section of the Carrizo aquifer.

Haynesville Shale and East Texas Basin: Water is generally plentiful in East Texas and no significant recycling/reuse and use for brackish water was documented during this study. We estimated it at 5%, mostly from treatment plants and produced water from Cotton Valley wells. We estimated that about 70% of the "new" water is groundwater.

Permian Basin: A significant percentage (30% or more) of the HF water used in both the Midland and Delaware basins is brackish. Nearly all of the water used is groundwater tapping aquifers such as the Ogallala (which is often brackish towards its southern domain, where the industry has many HF operations), and the Dockum, Trinity Edwards, Capitan, and other aquifers. The industry currently does little recycling/reuse, although several companies use produced water from conventional oil and gas operations. Such produced water has relatively low salinity at several places in the basin.

Anadarko Basin: This basin has hosted much recycling/reuse (estimated at 20%) and use of brackish water (estimated at 30%). Most of the "new" water is groundwater (estimated at 80%).

III-2-2 2011 HF Water Use and Consumption

Combining information collected from the IHS database, industry information, and selected information from the 2011 report results in an estimated water use for HF of ~81,500 AF across the state in 2011 (Table 9). The Barnett Shale and the Eagle Ford shale used a similar amount of

water (~25 kAF), but less fresh water was used in the Eagle Ford. The Permian Basin is catching up (~15 kAF), but it uses relatively less fresh water than the two shale plays. Water use in the Texas section of the Haynesville Shale is becoming subordinate to other plays located in the same area (for example, Cotton Valley). County-level water use (Table 10) shows that many counties across the state have some HF water use (126 counties with >1AF in 2011 and 26 counties with >1kAF). The top 10 HF users consist of Tarrant County in the Barnett core (8.8 kAF), Webb County in the southern Eagle Ford (4.6 kAF), Johnson County in the core of the Barnett Shale (4.2 kAF), Karnes County in the Eagle Ford (3.9 kAF), Wheeler County in the Granite Wash of the Anadarko Basin (3.8 kAF), Dimmit County in the Eagle Ford (3.7 kAF), Denton County in the core of the Barnett Shale (3.2 kAF), Montague County in the combo play of the Barnett Shale (3.2 kAF), La Salle County in the Eagle Ford (2.9 kAF), and Wise County in the core of the Barnett Shale (2.3 kAF). The top ten counties total about half of the HF water use in the state. The top 10 counties stay the same when only water consumption is considered despite some reshuffling because of the variable impact of recycling/reuse and brackish water use.

In the next section we compare our current findings to the findings of the 2011 report (that projected a water use of 62 kAF in 2011, Table 9) and explain the discrepancies.

Table 7. Estimated percentages of recycling/ reused and brackish water use in main HF areas in 2011.

Play / Region	Type	Current (2011) %
Permian Far West	Recycled/reused	0%
	Brackish	80%
	Fresh	**20%**
Permian Midland	Recycled/reused	2%
	Brackish	30%
	Fresh	**68%**
Anadarko Basin	Recycled/reused	20%
	Brackish	30%
	Fresh	**50%**
Barnett Shale	Recycled/reused	5%
	Brackish	3%
	Fresh	**92%**
Eagle Ford Shale	Recycled/reused	0%
	Brackish	20%
	Fresh	**80%**
East Texas Basin	Recycled/reused	5%
	Brackish	0%
	Fresh	**95%**

Table 8. Estimated groundwater / surface water split (does not include recycling / reuse)

Play / Region	Groundwater	Surface Water
Barnett Shale	20%	80%
Eagle Ford Shale	90%	10%
East Texas Basin	70%	30%
Anadarko Basin	80%	20%
Permian Basin	100%	0%

Table 9. HF water use in 2008 and 2011compared to the 2011 projected water use from 2008.

Play / Region Unit: kAF	2011 Actual Water Use	Fraction Non-R/R Non-brackish	2011 Actual Water Consumption	2011 Projected Water Use
Barnett Shale	25.75	0.92	23.69	33.08
Eagle Ford Shale	23.76	0.8	18.81	10.07
East Texas Basin	7.54	0.95	7.06	8.46
Anadarko Basin	6.52	0.5	3.21	2.26
Permian Basin	14.44	0.68 / 0.2	8.55	7.26
Gulf Coast Basin	3.49	0.95 / 0.8	3.31	1.00
Statewide	81.51	0.79*	64.63	62.13

FrackingWaterUse2008&2011_Bob-JPComp_2.xls

*: computed from state consumption and use columns (sum of other rows)

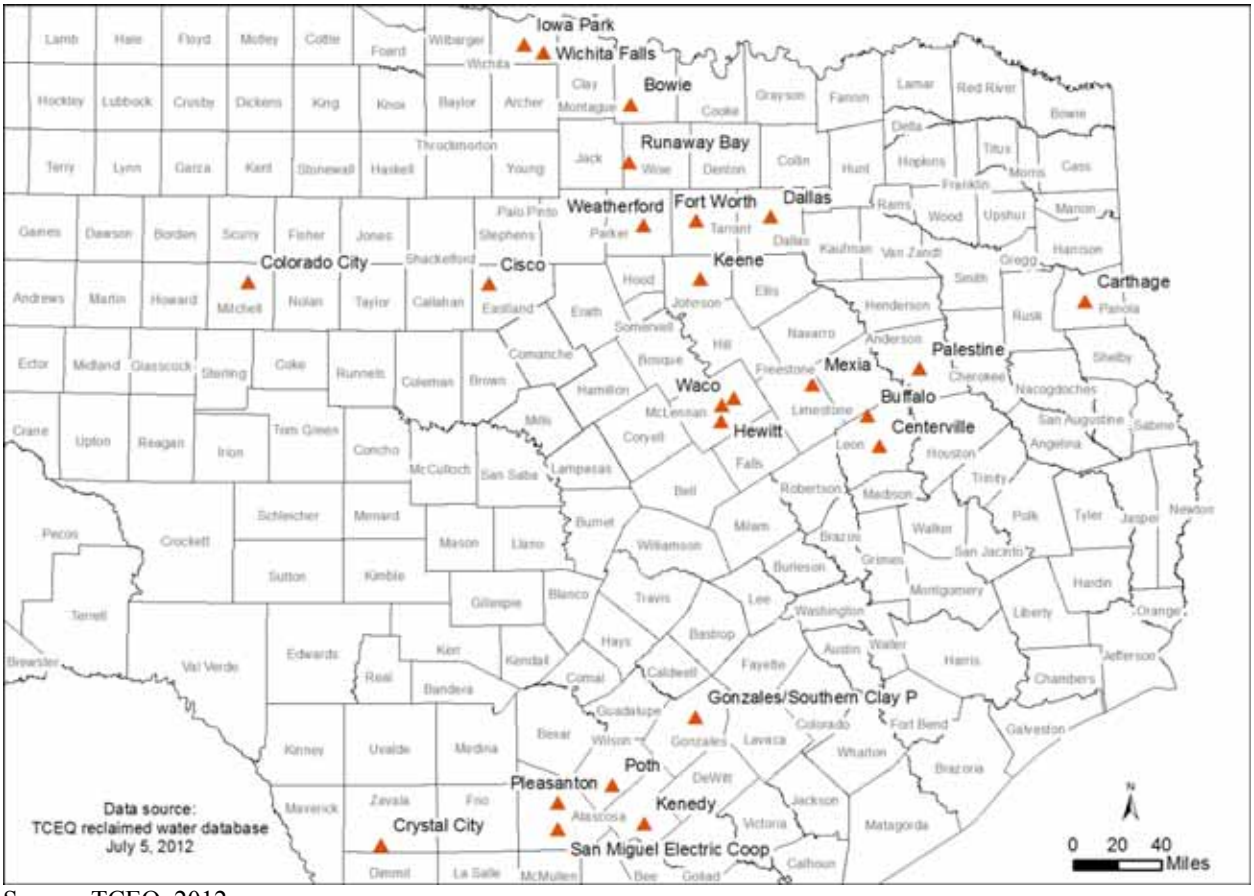
Table 10. County-level estimate of 2011 HF water use and water consumption (kAF).

County	HF Water Use (kAF)	HF Water Consumption (kAF)	County	HF Water Use (kAF)	HF Water Consumption (kAF)
Andrews	1.391	0.946	Limestone	0.268	0.214
Angelina	0.007	0.006	Lipscomb	0.382	0.191
Archer	0.017	0.016	Live Oak	0.972	0.777
Atascosa	1.009	0.807	Loving	0.189	0.038
Bee	0.066	0.053	McMullen	1.752	1.401
Borden	0.033	0.023	Madison	0.204	0.163
Brazos	0.238	0.191	Marion	0.010	0.010
Brooks	0.008	0.006	Martin	2.035	1.384
Burleson	0.247	0.197	Maverick	0.192	0.154
Caldwell	0.075	0.060	Midland	1.573	1.070
Carson	0.085	0.042	Milam	0.034	0.027
Cherokee	0.010	0.009	Mitchell	0.018	0.012
Clay	0.058	0.053	Montague	3.221	2.963
Cochran	0.031	0.021	Moore	0.076	0.038
Coke	0.001	n/a	Nacogdoches	1.128	1.072
Cooke	1.480	1.362	Newton	0.098	0.093
Crane	0.159	0.108	Nolan	0.011	0.008
Crockett	0.475	0.323	Nueces	0.016	0.013
Crosby	0.012	0.008	Ochiltree	0.273	0.136
Culberson	0.166	0.033	Orange	0.006	n/a
Dallas	0.079	0.073	Palo Pinto	0.041	0.038
Dawson	0.089	0.061	Panola	0.966	0.917
Denton	3.249	2.989	Parker	1.086	1.000
DeWitt	2.151	1.721	Pecos	0.110	0.022
Dimmit	3.706	2.965	Polk	0.133	0.126
Ector	0.756	0.514	Potter	0.044	0.022
Ellis	0.038	0.035	Reagan	1.240	0.843
Erath	0.012	0.011	Reeves	0.522	0.104
Fayette	0.132	0.106	Roberts	0.393	0.197
Franklin	0.014	0.014	Robertson	0.306	0.245
Freestone	0.424	0.339	Runnels	0.004	0.003
Frio	0.729	0.583	Rusk	0.158	0.150
Gaines	0.142	0.096	Sabine	0.147	0.139
Garza	0.001	n/a	San Augustine	1.622	1.541
Glasscock	1.434	0.975	Schleicher	0.090	0.061
Gonzales	2.224	1.779	Scurry	0.010	0.007
Grayson	0.021	0.020	Shackelford	0.002	0.002
Gregg	0.025	0.024	Shelby	1.419	1.348
Grimes	0.095	0.076	Sherman	0.002	0.001
Guadalupe	0.018	0.014	Smith	0.005	0.005
Hansford	0.011	0.005	Somervell	0.287	0.264
Hardeman	0.017	0.012	Starr	0.036	0.029
Harrison	0.893	0.849	Sterling	0.057	0.039
Hemphill	1.462	0.731	Stonewall	0.001	n/a
Henderson	0.012	0.012	Sutton	0.034	0.023
Hidalgo	0.059	0.047	Tarrant	8.805	8.101
Hill	0.131	0.120	Terrell	0.010	0.007
Hockley	0.005	0.003	Terry	0.003	0.002
Hood	0.645	0.593	Titus	0.003	0.003

County	HF Water Use (kAF)	HF Water Consumption (kAF)	County	HF Water Use (kAF)	HF Water Consumption (kAF)
Houston	0.178	0.142	Tyler	0.076	0.072
Howard	0.552	0.376	Upshur	0.004	0.004
Hutchinson	0.005	0.002	Upton	1.761	1.198
Irion	0.875	0.595	Ward	0.568	0.114
Jack	0.048	0.044	Washington	0.036	0.029
Jasper	0.087	0.083	Webb	4.596	3.677
Johnson	4.192	3.857	Wheeler	3.792	1.896
Karnes	3.869	3.095	Wilson	0.417	0.334
Kenedy	0.006	0.005	Winkler	0.062	0.012
Kleberg	0.034	0.028	Wise	2.314	2.129
La Salle	2.901	2.321	Yoakum	0.018	0.013
Lavaca	0.118	0.094	Young	0.008	0.007
Lee	0.131	0.105	Zapata	0.032	0.026
Leon	0.273	0.218	Zavala	0.407	0.127
			SUM	**81.50 kAF**	**64.63 kAF**

Note: filtered at 0.001 kAF

FrackingWaterUse2008&2011_Bob-JPComp_2.xls

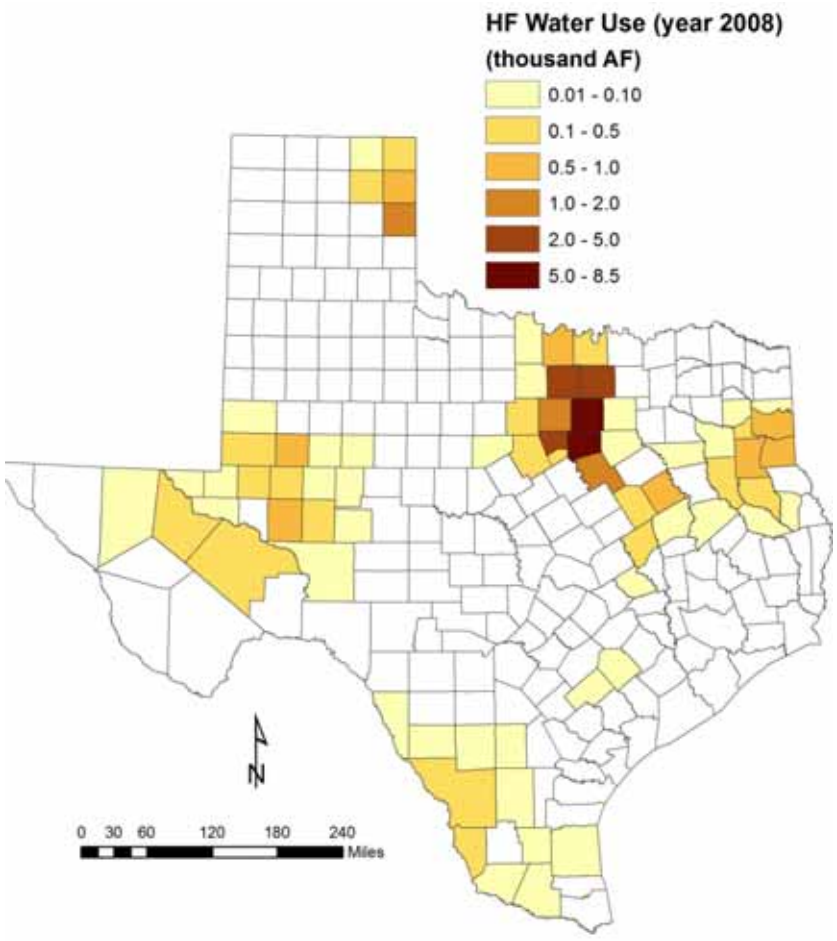


Source: TCEQ, 2012

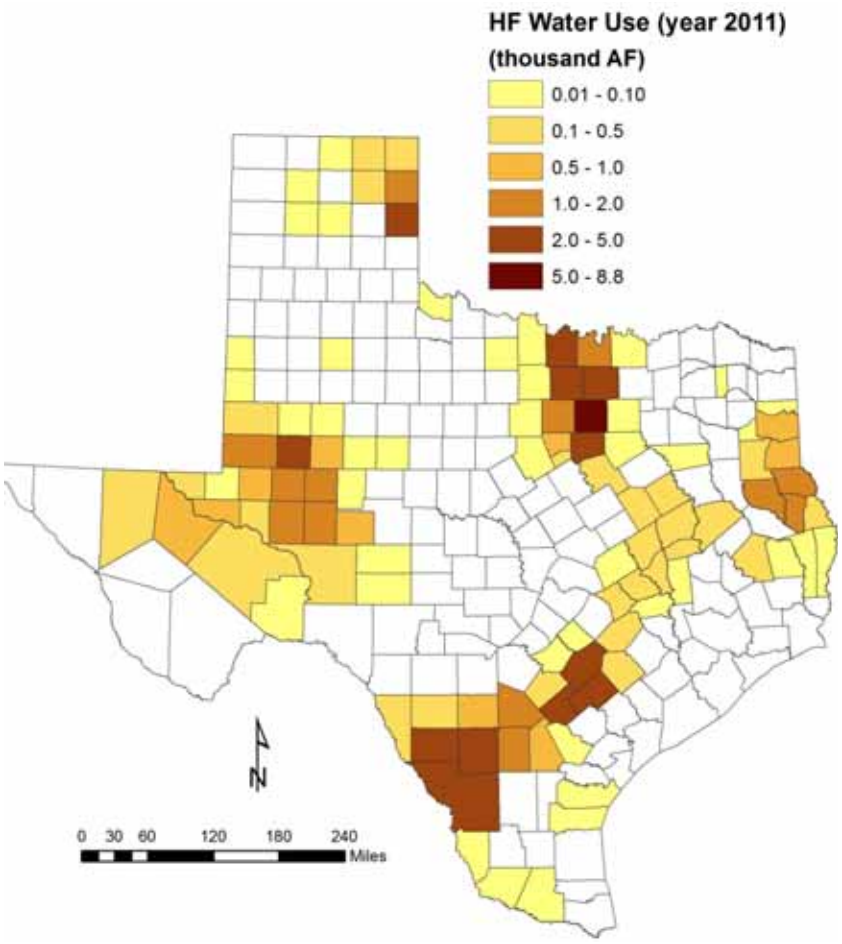
Figure 44. Location of waste water treatment facilities that provide or have provided water to the industry for HF as of July 2012.

III-3. Comparison to Earlier Findings

Projections made in 2009 for 2011 in the 2011 report underestimated water use by about 30% (81.5 kAF compared to 62.1 kAF, Table 9). It is important to understand the underlying causes in order to develop better projections in this document. Comparing actual water use in 2008 and 2011 (Figure 45) shows (1) extension of HF across the state, Barnett Shale stays relatively steady, fracturing in the Haynesville Shale and Anadarko Basin expands, and the Eagle Ford becomes much more prominent as does the Permian Basin. A bar plot illustrates the county-by-county discrepancies between projections and actual numbers (Figure 46). A cross-plot is a different way of presenting the same information (Figure 47), and it is apparent that most counties with larger water use (dots in the upper right-hand side of the side) were correctly accounted (no dots on either the x- or y-axis), even if it was underestimated (dots mostly below the 1:1 line). Major discrepancies occurred because there was no Barnett extension outside of the core area (for example, Bosque, Comanche, Erath, and Palo Pinto counties in Figure 46), and because of more and faster development in the Eagle Ford Shale and Permian Basin. Both these factors are connected to the drop in gas price and increase in oil price in the past 2 or 3 years, parameters notoriously difficult to predict.



~36,000 AF
(Nicot el al., 2011)



~81,500 AF
including ~17,000 AF of recycling/reuse and use of brackish water

Figure 45. Spatial distribution of HF water use in 2008 and 2011.

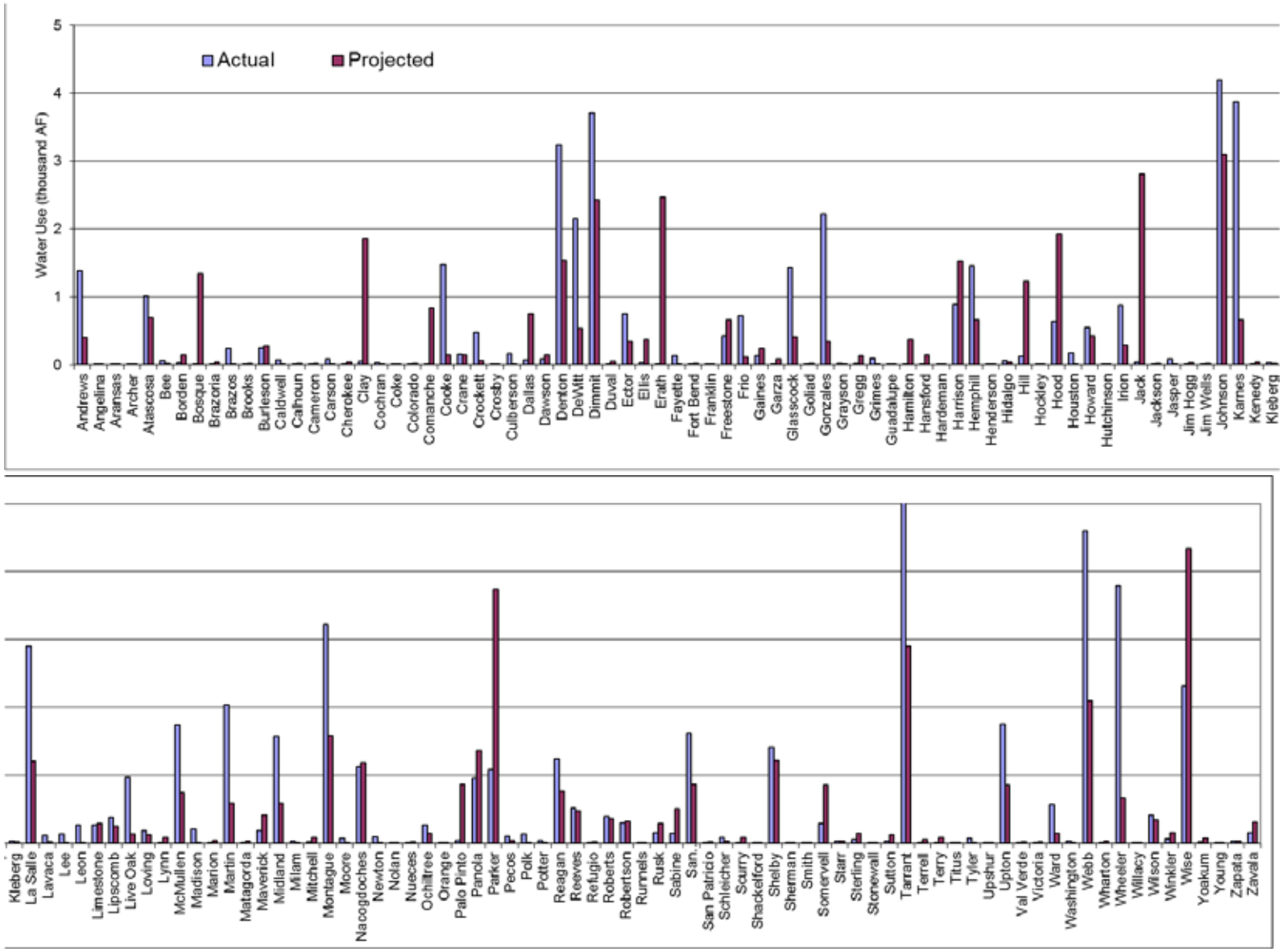
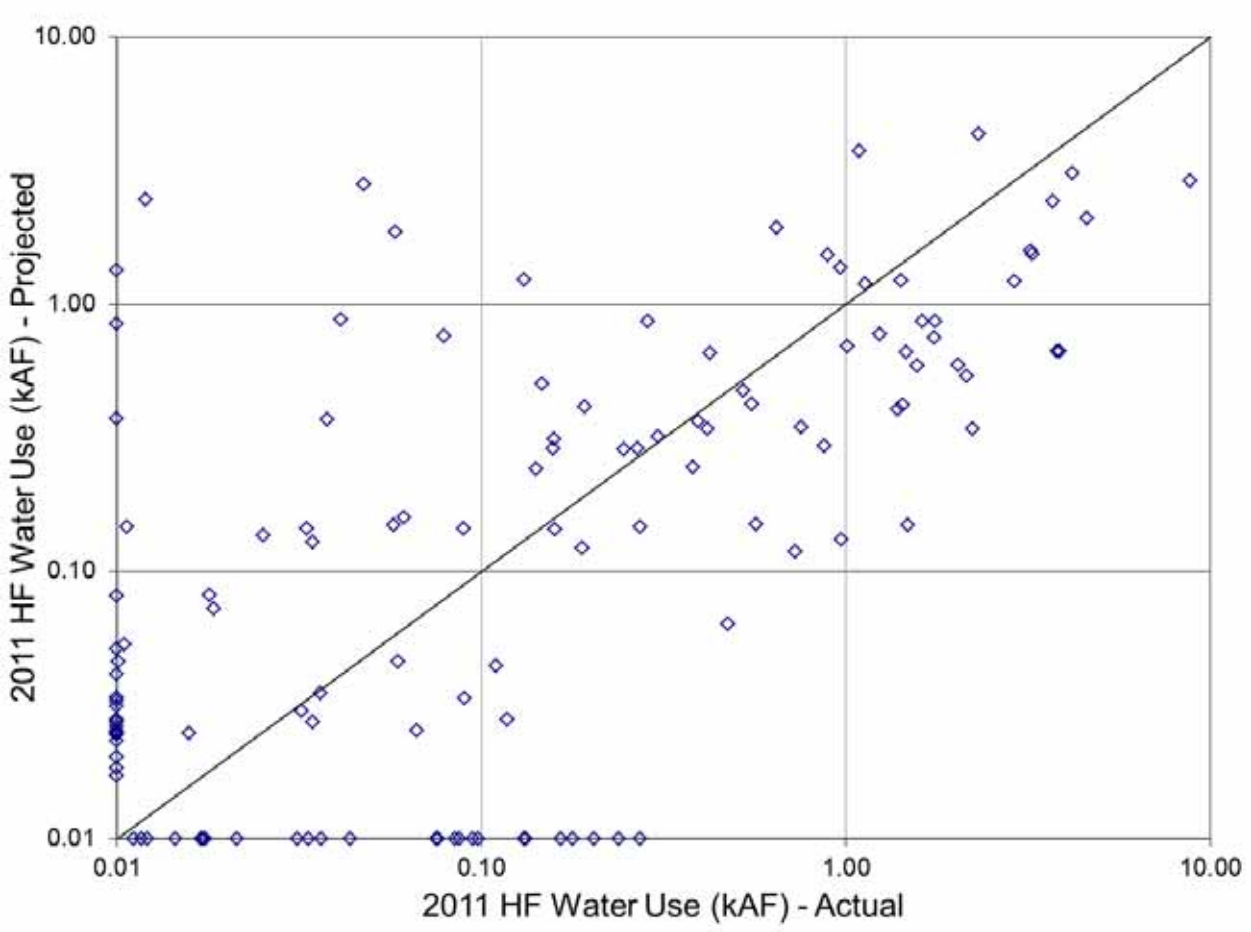


Figure 46. Bar plot comparison of 2011 actual water use to projections from 2009.



Note: Note the log-log scale.

Figure 47. County-level cross-plot comparison of 2011 actual water use to projections from 2008. Values on x- and y- axis represent counties whose actual (y-axis) / projected (x-axis) water use is 0. A total of 168 counties are represented.

III-4. Drilling Water Use

In the course of the study, we also collected information about drilling water use. Results are not sufficiently representative to change results presented in the 2011 report amounting to 8 kAF. The general observation, though, is that drilling requires water of better quality than HF although in smaller amounts (Table 11). The amount of water used depends on the length of the well and on operator preferences but also, more importantly, heavily on local factors. For example, in the Eagle Ford the drilling muds used in drilling through horizontal sections (for example, Fan et al., 2011) are oil-based.

Table 11. Drilling water use information

Play / Region	Range provided by operators in 1000's gal/well	Comments
Barnett Shale	250	N/A
	210-420	~Fresh
	168	~Fresh
	500	~Fresh
Eagle Ford Shale	125	N/A
	420	N/A
	160	~Fresh
	126	~Fresh
	252-420	~Fresh
East Texas Basin	600	N/A
	840-1,100	~Fresh
	420	~Fresh
Anadarko Basin	200	N/A
	420	~Fresh
Midland Basin (Permian Basin)	84	~Fresh
	100	N/A
	210	~Fresh
	210-420	~Fresh
Delaware Basin (Permian Basin)	100	N/A
	210-420	Brackish

Note: fresh is defined as TDS<3,000 mg/L

IV. Water Use Projections

This section describes projections for HF water use and fresh-water consumption in Texas to year 2060. As described in the 2011 report, all projections entail many uncertainties and those caveats are still valid in this update. In general, the life of the plays was extended beyond 2060, less prospectivity was given to the gas window, and steeper development to the oil window section of plays or tight oil plays. The overall results is that the HF water use will have a broad plateau at ~125 kAF/yr around the 2020-2030 decade and then slowly decrease with time to 2060 and beyond (Figure 48). However, the amount of fresh water consumed (that is, not recycled or reused or brackish water) will stay relatively constant at ~70 kAF despite the increase in water use and then slowly subside with the decrease in HF activities. Fresh-water use will decrease for two reasons: (1) the industry is getting better at reusing flow back (but sometimes limited by the small fraction coming back) and at finding alternate sources of recycling (treatment plants, produced water from conventional wells) and at using brackish water because of the technological advances in additives tolerating more saline water. And (2) the Permian Basin, which may become the focus of HF in Texas in the long run, offers great production potential. In the Permian Basin, fresh water is at a premium and brackish water is already used by the industry.

Total oil and gas water use and consumption (combining HF, waterflooding, and drilling) is presented in Figure 49. Oil and gas water use, consistent with the definition of make-up fresh water used in this document, was computed by summing HF water use (Figure 48), drilling water use –with no change from the 2011 report, and waterflood water use –computed from the 2011 report by adding fresh and brackish water use. Oil and gas water consumption was computed by summing HF water consumption (Figure 48), drilling water use –with no change from the 2011 report and the additional note that water use and consumption are identical. Waterflood water consumption is the same as water use in the 2011 report that represented fresh water use. Projected oil and gas water use and consumption are dominated by HF. By design, in the 2011 report, drilling technology was projected to move the industry away from the use of fresh water. Progress in waterflooding was also projected to decrease fresh water requirements but to increase brackish water use until the whole industry relies only on saline water (not showed). Under these assumptions, oil and gas industry water use is projected to peak with a broad plateau at 180 kAF in the 2020-2030 decade, slowly declining to ~60 kAF by 2060. Fresh water consumption in the oil and gas industry is projected to reach a maximum of ~100 kAF before the end of this decade and then to slowly decrease to a low level of a few tens of thousands AF by the middle of the century.

We did not account for many unknowns that could possibly impact the results as they did in the Eagle Ford Shale when the industry switched from slick-water fracs to gel fracs in the oil window that use less water. The Eagle Ford was the only play in which we observed such a trend, everywhere else the trend (based on 2 to 5 years of data) shows an increase or a steady value in water intensity (Table 12). Data about recycling/reuse and brackish water use were derived from industry information of these uses as of today and in 2020 (Table 13). The most likely values from 2011 and 2020 are essentially estimated directly from the various responses in a given play. Extrapolation to 2060 and translation to high and low scenarios for all years starting in 2012 are speculative and are based on industry trends and on the general knowledge of the authors about fresh and brackish water aquifers and of their yields around the state. The

amount of reuse cannot be larger than the amount of flow back / produced water from recently fractured wells and at the play level reuse is likely less because of the operational issues of transporting water. Some plays, such as the Haynesville and Eagle Ford Shales, are at a disadvantage for this; they produce back less than 20% of the injected water (Table 14). They, and others, could however take advantage of produced water from other formations.

We did not deviate much from the overall water use of the 2011 report because of constraints accounted for the 2011 report and related to drilling rig count, labor force availability/staff shortage, infrastructure development, and other factors. National rig count seems steady at ~2,000 or slightly lower in the past year (~50% of them in Texas), but drillers are improving at operating them, which suggests that the projections presented in this update are consistent with the number of drilling rigs currently available.

Cumulative water use is related to the eventual well density or lateral spacing. Ultimate average spacing between laterals, or vertical well density, is the parameter driving water use along with water intensity. Typical vertical well spacing is 1 well per 40 acres; that ratio can decrease to 1 well per 20 or 10 acres in some instances. Typical lateral spacing can be computed from 1 horizontal well per 160 acres. If lateral length is 5,000 ft, the resulting spacing between laterals is 1,400 ft. If the horizontal well density declines to 1 well per 40 acres, lateral spacing is 350 ft. This update document assumes a lateral spacing of 1000 ft, perhaps smaller in oil windows (Figure 51).

County-level projections for HF water use and water consumption are listed in Table 15. The county coverage is essentially the same as in the 2011 report with the addition of four counties in East Texas (Polk, Tyler, Jasper, and Newton counties, Figure 50). Total oil and gas (combining HF, waterflooding, and drilling) county-level projections are presented in Table 16.

The following paragraphs address HF projection issues specific to each play and region. Each play is represented by two plots. One plot compares projections from the 2011 report to projections from this update. The second plot displays water use and fresh water consumption in the high, low, and most likely scenarios. Only the latter is displayed in the first plot and is retained as the preferred set of projections to be used by the TWDB. As explained in the Methodology Section (Section II), low and high scenarios were derived by varying two factors: (1) the prospectivity factor, which assesses the ultimate amount of HF in a play, varies on a county and play basis from 1 to 0, with 1 meaning the county is within the core area and highly prospective (for example, Tarrant County in the Barnett Shale) and near- zero values suggesting that little of the county will be developed (for example ,Shackelford County in the Barnett Shale); and (2) coefficients for recycling/reuse and brackish water use (Table 13). The prospectivity factor was changed according to a sliding linear scale: a value of 1 stays at 1 but a value of 0.2 either goes to zero (low water use scenario) or 0.4 (high water use scenario). The change was made systematically with no tentative exercise to tailor it to each county/play couple. In the case of tight oil/ tight gas plays, a third factor was varied. This factor varies from 0 to 1 and addresses the spatial coverage of the county that could ultimately undergo HF. In the case of resource plays such as shale plays, the factor is constant and close to one because the whole footprint of the play is potentially a target for drilling. The only unknown is the well density which is accounted for through the prospectivity factor. In tight oil/gas plays, it cannot be assumed that the whole footprint of the formation will experience HF because some parts of it can be properly produced through conventional wells. This third factor was used in the East

Texas (Cotton Valley), Anadarko (Granite Wash), Gulf Coast (Austin Chalk), and Permian basins.

Barnett Shale: In this play with the longest history, we considerably decreased the prospectivity factors outside of the core area in the most likely scenario. That is, instead of increasing water use because of the expansion of the productive Barnett Shale footprint, we assumed that most of the HF will stay confined to the core area and stay relatively stable for a few years before slowly decreasing (Figure 52a). The peak from earlier projections has disappeared and water use should stay below 30 kAF and decrease more slowly than projected in the 2011 report. The high water use scenario projection (Figure 52b) displays a small increase in water use (but not in water consumption) in the 2020 decade because the prospectivity factors are closer to those used in the 2011 report.

Eagle Ford Shale: Projections for this play display a decrease in water use compared to those projected values of the 2011 report (Figure 53a) because of the observed decrease in water intensity that we assumed will hold in the future. The projections suggest a slow increase in water for the next 10 years with a broad peak at ~35kAF and a slow decrease beyond 2060. Unlike the Barnett with a clearly delimited core, we assumed that most counties in the Eagle Ford are highly prospective and thus there is not much variation between high and low scenario projections except when recycling/reuse and use of brackish water are included (Figure 53b).

Pearsall Shale: This gas play was briefly hydraulically fractured in the mid-2000's and has not received a lot of attention since then. However, initial production estimates suggest that the play will be produced in the future. We used the same water use parameters in the Pearsall as those in the Eagle Ford Shale because these plays are geographically close. Projections from the 2011 report were only slightly modified displacing the peak water use at ~10 kAF by about 5 years into the future (Figure 54a). As was the case for the Eagle Ford, the high and low scenarios are mostly impacted by the amount of recycling/reuse and brackish water use (Figure 54b).

TX-Haynesville and Bossier Shales: The Haynesville and Bossier Shales have declined in operator interest because of their relatively high operational cost and low gas prices. They are, however, still likely to produce significant amounts of gas in the future, albeit at a lower rate than anticipated in the 2011 report. Projections of this update document show a decreased and broader peak (Figure 55a), with annual water use slated to be no higher than ~12kAF. A minor player, the Haynesville-West play will possibly undergo some development on the western flank of the East Texas Basin and its water use projections stay similar to that of the 2011 report (Figure 56a), with a decrease peak as well. Low and high scenario projections stay relatively close together (Figure 55b), because there is little variability in terms of projected non-fresh water use (almost none).

Other East Texas Formations: This category includes all formations except the Haynesville and Bossier Shales, such as the Cotton Valley, James Lime, Bossier Sands, and others. The same water consumption data used in the Haynesville were used for this group of formations. Relative to the 2011 report projections, the projections derived in this update assumed a broader peak displaced toward the future by ~10 years (Figure 57a). Projected maximum water use is estimated at <5 kAF/yr. The small variance between water use and water consumption is explained by the location of the plays in East Texas where fresh water is relatively abundant and the large differences between the different scenario projections is due to the spread of the third factor, addressing spatial coverage of the formation of interest (Figure 57b).

Gulf Coast Formations: Amount of water use and consumption in the Gulf Coast Basin outside of the shale plays is very uncertain. The Gulf Coast Basin is the area in Texas that has experienced the least HF (Nicot et al., 2011) and explained the large range of projections between the different scenarios (Figure 58b). This category include formations such as the Olmos Sands and the Austin Chalk, and these projections assumed that water use will peak at ~8kAF in the 2020's (Figure 58a). Water consumption is assumed to be much lower because most of the plays are in South Texas, where there are some brackish water resources.

Anadarko Basin: Anadarko Basin consists mostly of the Granite Wash in Hemphill and Wheeler counties and the Marmaton/Cleveland in Ochiltree and Lipscomb counties. Current water use in this basin is much higher than anticipated in the 2011 report projections. We revisited prospectivity factors and the projected water use reaches a broad peak of ~9kAF in the 2020's (Figure 59a) with a smaller projected water consumption because of anticipated recycling/reuse and brackish water use. However, the uncertainty in final coverage put this basin in the same category as the Gulf Coast Basin and East Basin category, resulting in a large spread of potential outcomes (Figure 59b).

Permian Basin: As has the Anadarko Basin, the Permian Basin has grown much faster than anticipated and water use projections call for a plateau at ~40 kAF during the 2020-2040 period (Figure 60a) concomitant with a fairly stable fresh water consumption at 10-15 kAF. The large gap between water use and water consumption, much larger than presented in the 2011 report (Figure 60a), is due to the expectation of availability of significant amounts of brackish water and of their extensive use by the industry (as currently documented by anecdotal evidence). The large range in outcome from the different scenarios is related to the unknowns in spatial coverage of the non-shale plays (Figure 60b). We now turn to the description of the major components making up water use in the Permian Basin. Although the Barnett-Woodford system in the Permian Basin has received limited interest, we assume it will produce gas in the future (Figure 61a). The most likely scenario calls for a peak at ~5 kAF in 2035 but with the possibility of a high scenario with a much higher water use and a low scenario with no development. Development centered on the Wolfcamp is more certain and differences between high and low scenario projections were derived mostly from assumptions on the level of use of non-fresh water(Figure 61b). The other formations in the Permian Basin also display the same uncertainty related to the amount of spatial coverage ("third factor" as described above). The most likely scenario projection is estimated to have a broad peak in the 15-20 kAF range for many years with considerably less water consumption (Figure 61c).

Table 12. Recent trends in well completion and water use in hydraulic-fractured plays.

Play	Well Type	~# of Recent Wells/yr	Recent Trend (well/yr)	Water Use / well (Mgal)	Water Use Intensity (gal/ft)	Recent Trend (water use)
Barnett	H	1500	down / steady	n/a	1200	steady
Eagle Ford	H	1000	strongly up	n/a	850	down
TX-Haynesville	H	250	up	n/a	1400	steady
Granite Wash	H	250	strongly up	n/a	1200	steady / up
	V	60	strongly down	1500	800	steady
Cleveland	H	100	steady	n/a	250	steady
	V	20	down	1.7	2000	steady
Marmaton	H	30	strongly up	n/a	250	steady
	V	10	steady	1.0	2500	up
Cotton Valley	H	100	up	n/a	1000	steady
	V	300	strongly down	0.8	1200	steady
Olmos	H	50	up	n/a	1000	up
	V	100	strongly down	0.15	2500	steady
Wolfcamp	H	150	strongly up	n/a	900	strongly up
Wolfberry	V	2000	up	1.0	350	up
Canyon	V	300	down	0.4	500	up
Clear Fork	V	800	up	0.8	350	up
San Andres	H	50	strongly down	n/a	350	strongly up
	V	800	steady / up	0.15	500	steady

Table 13. Coefficients (%) to compute water consumption to be applied to total water use.

Play / Region		High Water Use	Most Likely	Low Water Use
Far West Permian Basin	**Recycling**			
	2011	0	0	0
	2020	0	50	40
	2060	0	40	40
	Brackish			
	2011	80	80	80
	2020	80	30	50
	2060	80	40	50
Permian Midland Basin	**Recycling**			
	2011	2	2	2
	2020	2	25	30
	2060	2	30	40
	Brackish			
	2011	30	30	30
	2020	30	40	40
	2060	30	40	50
Anadarko Basin	**Recycling**			
	2011	20	20	20
	2020	20	30	40
	2060	20	40	40
	Brackish			

Play / Region		High Water Use	Most Likely	Low Water Use
	2011	30	30	30
	2020	30	30	30
	2060	30	30	40
Barnett Shale	**Recycling**			
	2011	5	5	5
	2020	5	10	25
	2060	5	20	20
	Brackish			
	2011	3	3	3
	2020	3	15	20
	2060	3	25	25
Eagle Ford Shale	**Recycling**			
	2011	0	0	0
	2020	0	10	10
	2060	0	10	10
	Brackish			
	2011	20	20	20
	2020	20	40	50
	2060	20	50	50
South Texas	**Recycling**			
	2011	0	0	0
	2020	0	10	10
	2060	0	10	10
	Brackish			
	2011	20	20	20
	2020	20	40	50
	2060	20	50	50
East Texas	**Recycling**			
	2011	5	5	5
	2020	5	10	10
	2060	5	10	10
	Brackish			
	2011	0	0	0
	2020	0	0	10
	2060	0	10	10

Table 14. Estimated flow back/produced water volume relative to HF injected volume.

Play / Region	Comment
Delaware Basin (Permian Basin)	Close to 100% in year 1, 150% well life >200% well life
Midland Basin (Permian Basin)	50%-100% in year 1
Anadarko Basin	~50% in month 1, 90% at month 6
Barnett Shale	10-20% month 1, 20-60% well life 70% year1; 150% in 5 years
Eagle Ford Shale	20% over life; 20% over life
Haynesville Shale	20% over life; 15% over life
Cotton Valley Fm.	60% month 1, >100% well life; 40% or 100% over life

Table 15. County-level estimate of 2012-2060 projections for HF water use and water consumption (AF).

	Water Use (AF)											Water Consumption (AF)										
County	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Anderson	0	31	58	89	119	131	139	124	105	85	66	0	23	41	64	86	97	104	92	76	61	46
Andrews	1,391	1,617	2,140	2,053	1,965	1,878	1,654	1,431	1,207	983	806	946	862	749	690	634	580	501	425	351	279	224
Angelina	7	60	160	260	360	379	345	310	276	241	207	6	56	144	231	315	327	293	260	228	196	165
Aransas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Archer	17	81	183	284	385	354	321	289	257	225	193	16	68	137	206	270	239	209	181	154	129	106
Armstrong	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Atascosa	1,009	2,902	2,638	2,589	2,594	2,598	2,602	2,314	1,953	1,591	1,230	807	2,064	1,583	1,500	1,443	1,386	1,329	1,144	935	736	545
Austin	0	0	98	195	293	264	234	205	176	146	117	0	0	59	115	169	148	129	110	92	75	59
Bailey	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bandera	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0
Bastrop	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Baylor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bee	66	80	101	108	94	81	67	54	40	27	13	53	60	64	67	57	48	39	31	23	15	7
Bell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bexar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blanco	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Borden	33	228	638	892	899	906	764	622	480	338	230	23	122	223	307	303	300	248	198	150	104	69
Bosque	0	192	329	466	603	553	502	452	402	352	301	0	162	247	338	422	373	327	283	241	202	166
Bowie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brazoria	0	41	60	79	97	91	79	67	55	43	31	0	31	38	49	59	54	46	38	31	24	17
Brazos	238	322	696	931	1,166	1,036	905	775	644	514	384	191	243	431	559	681	592	506	423	343	267	193
Brewster	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brooks	8	37	49	62	62	54	46	38	30	22	14	6	28	31	38	38	32	27	22	17	12	8
Brown	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burleson	247	331	943	1,409	1,877	1,676	1,474	1,273	1,071	867	665	197	250	580	840	1,090	952	819	690	567	447	334
Burnet	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Caldwell	75	90	116	103	90	77	64	52	39	26	13	60	68	73	64	55	46	38	29	22	14	7
Calhoun	0	25	33	42	42	37	31	26	21	15	10	0	19	21	26	26	22	18	15	11	8	5
Callahan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cameron	0	37	50	62	62	54	46	38	30	22	14	0	28	31	38	38	32	27	22	17	12	8
Camp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carson	85	0	0	0	0	0	0	0	0	0	0	42	0	0	0	0	0	0	0	0	0	0
Cass	0	10	25	41	56	68	60	52	45	37	30	0	9	24	38	52	60	52	45	38	31	24
Castro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chambers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cherokee	10	70	128	186	244	284	253	221	190	158	126	9	66	122	173	223	254	221	189	159	129	101
Childress	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clay	58	194	355	516	678	621	565	508	452	395	339	53	164	266	374	474	419	367	318	271	227	186
Cochran	31	94	121	149	176	203	180	158	135	113	90	21	50	42	51	59	67	59	50	42	35	27
Coke	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coleman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colorado	0	38	517	996	1,462	1,314	1,166	1,018	870	722	574	0	29	312	587	843	741	643	548	458	371	287
Comal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Comanche	0	125	228	332	436	392	349	305	261	218	174	0	105	171	241	305	265	227	191	157	125	96
Concho	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cooke	1,480	1,653	1,294	934	575	215	0	0	0	0	0	1,362	1,396	970	677	402	145	0	0	0	0	0
Coryell	0	289	1,012	947	684	421	158	0	0	0	0	0	244	759	686	479	284	103	0	0	0	0

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Cottle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crane	159	339	438	559	681	802	729	656	583	510	438	108	181	153	189	223	257	229	203	177	152	128
Crockett	475	996	1,636	1,946	1,760	1,475	1,190	905	620	335	149	323	531	573	669	594	489	387	288	194	103	45
Crosby	12	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0
Culberson	166	141	188	576	963	1,280	1,163	1,047	931	814	698	33	75	66	149	231	290	262	235	207	180	154
Dallam	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dallas	79	654	1,018	848	679	509	339	170	0	0	0	73	553	763	615	475	343	220	106	0	0	0
Dawson	89	476	724	918	954	990	844	699	553	408	294	61	254	253	308	308	308	257	208	160	115	80
Deaf Smith	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Delta	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Denton	3,249	3,159	2,106	1,053	0	0	0	0	0	0	0	2,989	2,667	1,579	763	0	0	0	0	0	0	0
DeWitt	2,151	1,977	1,773	1,569	1,354	1,130	907	684	460	237	14	1,721	1,407	1,065	924	780	638	500	369	243	122	7
Dickens	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dimmit	3,706	4,777	4,765	4,857	4,871	4,834	4,232	3,489	2,746	2,002	1,259	2,965	3,407	2,828	2,774	2,669	2,534	2,145	1,710	1,294	895	516
Donley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Duval	0	70	94	117	118	103	87	72	57	42	27	0	53	59	73	72	61	51	41	32	23	14
Eastland	0	0	424	642	550	458	367	275	184	92	0	0	0	318	465	385	309	238	172	110	53	0
Ector	756	983	1,340	1,434	1,529	1,484	1,309	1,134	959	784	644	514	524	469	478	488	451	390	332	274	219	176
Edwards	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ellis	38	87	126	166	206	185	164	144	123	103	82	35	74	95	120	144	125	107	90	74	59	45
El Paso	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Erath	12	163	253	343	433	397	361	325	289	253	217	11	137	190	249	303	268	235	203	173	145	119
Falls	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fannin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fayette	132	1,081	2,329	2,093	1,822	1,526	1,229	932	636	340	43	106	773	1,402	1,236	1,054	864	681	505	337	176	23
Fisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Floyd	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Foard	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fort Bend	0	35	46	58	58	51	43	36	28	21	14	0	26	29	36	35	30	25	20	16	11	7
Franklin	14	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0
Freestone	424	750	975	1,229	1,424	1,404	1,241	1,076	912	748	584	339	678	846	1,042	1,196	1,164	1,012	863	720	582	449
Frio	729	1,119	1,146	1,176	1,189	1,159	1,127	1,097	947	769	589	583	809	701	708	692	647	602	559	465	364	266
Gaines	142	830	1,273	1,709	1,881	1,841	1,582	1,323	1,064	805	599	96	443	445	563	588	542	456	372	290	212	152
Galveston	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Garza	1	237	315	394	473	426	379	331	284	237	189	0	126	110	136	160	141	123	106	89	72	57
Gillespie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glasscock	1,434	1,938	2,621	2,466	2,311	1,978	1,646	1,313	980	648	427	975	1,033	917	848	780	655	535	419	306	198	128
Goliad	0	34	45	56	56	49	42	35	27	20	13	0	25	28	35	34	29	24	20	15	11	7
Gonzales	2,224	1,746	1,552	1,358	1,164	970	776	582	388	194	0	1,779	1,241	931	798	669	545	427	313	204	99	0
Gray	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Grayson	21	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	0	0
Gregg	25	134	224	313	402	449	405	362	318	274	230	24	127	208	284	357	391	347	305	263	223	184
Grimes	95	125	287	448	569	506	443	380	317	254	191	76	94	178	270	334	291	249	209	170	133	97
Guadalupe	18	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0
Hale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hamilton	0	251	304	253	203	152	101	51	0	0	0	0	212	228	184	142	103	66	32	0	0	0
Hansford	11	0	513	1,025	879	732	586	439	293	146	0	5	0	205	397	329	265	205	148	95	46	0
Hardeman	17	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
Hardin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Harris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Harrison	893	1,578	2,223	2,012	1,851	1,689	1,527	1,365	1,203	1,041	880	849	1,479	2,030	1,808	1,636	1,469	1,307	1,149	996	847	704

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Hartley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Haskell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hays	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hemphill	1,462	2,484	2,231	1,978	1,724	1,470	1,217	963	710	456	203	731	1,132	892	766	646	533	426	325	231	143	61
Henderson	12	46	124	201	278	333	296	259	222	185	148	12	44	117	187	254	297	259	222	186	151	118
Hidalgo	59	63	83	104	105	91	78	64	51	37	24	47	47	53	65	64	54	45	37	28	20	13
Hill	131	1,429	1,225	1,021	816	612	408	204	0	0	0	120	1,207	919	740	571	413	265	128	0	0	0
Hockley	5	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Hood	645	409	580	751	921	829	737	645	553	461	369	593	346	435	544	645	560	479	403	332	265	203
Hopkins	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Houston	178	237	305	271	237	203	170	135	102	68	34	142	179	193	168	144	121	99	77	57	37	18
Howard	552	1,471	2,360	2,822	2,642	2,250	1,859	1,468	1,076	685	422	376	784	826	970	892	745	604	468	336	210	126
Hudspeth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hutchinson	5	0	90	180	154	128	103	77	51	26	0	2	0	36	70	58	47	36	26	17	8	0
Irion	875	1,478	2,429	2,889	2,613	2,190	1,766	1,343	920	497	221	595	788	850	993	882	725	574	428	287	152	66
Jack	48	242	363	485	605	545	485	424	363	303	242	44	204	273	351	424	368	315	265	218	174	133
Jackson	0	34	45	56	56	49	42	35	28	20	13	0	25	29	35	34	29	25	20	15	11	7
Jasper	87	105	135	120	105	90	75	60	45	30	15	83	79	86	75	64	54	44	34	25	16	8
Jeff Davis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jefferson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jim Hogg	0	45	60	75	75	65	56	46	37	27	17	0	34	38	46	46	39	32	26	20	15	9
Jim Wells	0	34	45	57	57	50	42	35	28	21	13	0	26	29	35	35	30	25	20	15	11	7
Johnson	4,192	4,038	3,365	2,692	2,019	1,346	673	0	0	0	0	3,857	3,410	2,524	1,952	1,413	909	437	0	0	0	0
Jones	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Karnes	3,869	2,749	2,457	2,165	1,863	1,554	1,245	937	629	320	11	3,095	1,956	1,475	1,273	1,073	876	686	505	331	165	6
Kaufman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kendall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kenedy	6	57	76	95	95	83	71	58	46	34	22	5	43	48	59	58	49	41	33	26	19	12
Kent	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kimble	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
King	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kinney	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kleberg	34	37	49	62	62	54	46	38	30	22	14	28	28	31	38	38	32	27	22	17	12	8
Knox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lampasas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
La Salle	2,901	4,432	4,425	4,532	4,621	4,698	4,147	3,440	2,732	2,025	1,318	2,321	3,154	2,612	2,563	2,499	2,427	2,070	1,659	1,265	889	530
Lavaca	118	913	1,522	1,388	1,241	1,086	930	775	620	464	309	94	651	915	818	716	613	513	418	326	239	155
Lee	131	203	392	508	624	553	484	414	345	274	204	105	152	243	305	365	316	270	226	184	142	103
Leon	273	663	1,289	1,800	2,309	2,192	1,934	1,674	1,416	1,155	898	218	487	831	1,166	1,487	1,415	1,225	1,041	864	693	529
Liberty	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limestone	268	307	347	388	410	376	332	287	242	197	153	214	281	307	333	346	312	270	229	190	153	116
Lipscomb	382	560	1,026	876	725	574	423	272	121	0	0	191	255	410	339	272	208	148	92	39	0	0
Live Oak	972	783	729	676	692	720	748	776	689	575	461	777	558	439	399	392	388	384	379	324	261	200
Llano	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loving	189	313	418	561	704	690	627	565	502	439	376	38	167	146	187	227	213	191	169	147	127	107
Lubbock	0	0	0	51	103	154	140	126	112	98	84	0	0	0	10	21	31	28	25	22	20	17
Lynn	0	0	246	336	427	517	460	402	345	287	230	0	0	86	116	144	171	149	128	108	88	69
McCulloch	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
McLennan	0	53	120	187	253	228	203	177	152	127	101	0	45	90	135	177	154	132	111	91	73	56
McMullen	1,752	2,545	2,762	3,067	3,329	3,562	3,306	2,930	2,553	2,177	1,801	1,401	1,815	1,627	1,729	1,797	1,840	1,658	1,430	1,211	1,001	801
Madison	204	261	561	750	940	832	727	622	518	413	308	163	197	348	451	549	475	406	339	275	214	155
Marion	10	121	270	420	569	579	522	466	408	351	295	10	114	249	380	506	506	449	393	339	286	236
Martin	2,035	2,446	3,071	2,824	2,577	2,267	1,892	1,516	1,141	765	512	1,384	1,305	1,075	963	855	731	597	468	344	224	145
Mason	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Matagorda	0	46	61	77	77	67	57	47	37	28	18	0	35	39	48	47	40	33	27	21	15	9
Maverick	192	1,574	1,857	2,241	2,626	3,010	2,843	2,538	2,234	1,928	1,623	154	1,119	1,074	1,226	1,368	1,501	1,376	1,195	1,022	856	698
Medina	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Menard	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Midland	1,573	2,640	3,265	3,034	2,803	2,465	2,045	1,625	1,205	785	488	1,070	1,408	1,143	1,034	928	791	643	499	361	227	136
Milam	34	0	0	0	0	0	0	0	0	0	0	27	0	0	0	0	0	0	0	0	0	0
Mills	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mitchell	18	238	317	397	476	428	381	333	286	238	190	12	127	111	136	161	142	124	106	89	73	57
Montague	3,221	3,496	2,997	2,497	1,998	1,498	999	499	0	0	0	2,963	2,952	2,248	1,810	1,398	1,011	649	312	0	0	0
Montgomery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moore	76	0	0	0	0	0	0	0	0	0	0	38	0	0	0	0	0	0	0	0	0	0
Morris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Motley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nacogdoches	1,128	1,424	2,066	1,937	1,809	1,659	1,503	1,347	1,191	1,036	880	1,072	1,327	1,873	1,731	1,593	1,438	1,283	1,132	985	842	704
Navarro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Newton	98	125	161	143	125	108	89	71	54	36	18	93	94	102	89	76	64	52	41	30	20	9
Nolan	11	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0
Nueces	16	34	45	56	56	49	42	35	28	20	13	13	25	29	35	34	29	25	20	15	11	7
Ochiltree	273	408	748	985	815	646	476	306	136	0	0	136	186	299	382	306	234	166	103	44	0	0
Oldham	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Orange	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Pinto	41	194	356	518	680	612	544	476	408	340	272	38	164	267	376	476	413	354	298	245	196	150
Panola	966	1,412	1,988	1,801	1,655	1,511	1,366	1,221	1,077	932	787	917	1,323	1,816	1,618	1,464	1,314	1,169	1,028	891	758	630
Parker	1,086	925	1,255	1,585	1,916	1,724	1,533	1,341	1,149	958	766	1,000	781	941	1,149	1,341	1,164	996	838	690	551	421
Parmer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pecos	110	130	173	387	601	746	674	601	528	456	383	22	69	60	108	156	180	161	142	123	105	87
Polk	133	180	232	206	180	155	129	103	77	52	26	126	136	147	128	110	92	75	59	43	28	14
Potter	44	0	0	0	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	0	0
Presidio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Randall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reagan	1,240	3,207	4,019	3,627	3,236	2,844	2,332	1,820	1,308	796	444	843	1,710	1,407	1,247	1,092	942	758	580	409	244	133
Real	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Red River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reeves	522	866	1,155	1,744	2,333	2,509	2,304	2,098	1,893	1,687	1,481	104	462	404	556	705	713	646	581	518	456	395
Refugio	0	32	42	53	53	46	39	33	26	19	12	0	24	27	33	32	27	23	19	14	10	7
Roberts	393	1,628	1,419	1,210	1,002	793	584	376	167	0	0	197	742	568	469	376	287	205	127	54	0	0
Robertson	306	587	741	773	806	734	639	544	449	354	259	245	501	587	619	648	584	500	419	342	268	196
Rockwall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Runnels	4	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Rusk	158	477	930	1,384	1,838	1,707	1,542	1,378	1,213	1,048	884	150	446	850	1,245	1,627	1,487	1,322	1,161	1,005	853	707
Sabine	147	235	470	705	940	861	783	705	627	548	470	139	218	423	625	823	743	666	590	517	445	376
San Augustine	1,622	2,092	1,953	1,814	1,674	1,534	1,395	1,256	1,116	977	837	1,541	1,941	1,758	1,610	1,465	1,323	1,186	1,052	921	793	670
San Jacinto	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Patricio	0	28	37	46	46	40	34	28	22	17	11	0	21	23	28	28	24	20	16	13	9	6

	Water Use (AF)											Water Consumption (AF)										
County	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
San Saba	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Schleicher	90	312	468	568	584	507	430	354	277	200	140	61	166	164	195	197	168	140	113	87	61	42
Scurry	10	0	249	341	432	524	466	408	349	291	233	7	0	87	117	146	174	151	130	109	89	70
Shackelford	2	0	156	311	467	421	374	327	280	234	187	2	0	117	226	327	284	243	204	168	134	103
Shelby	1,419	1,658	3,073	2,929	2,785	2,621	2,377	2,133	1,889	1,645	1,400	1,348	1,539	2,771	2,607	2,446	2,270	2,027	1,790	1,561	1,337	1,120
Sherman	2	0	0	92	184	158	132	105	79	53	26	1	0	0	36	69	57	46	36	26	16	8
Smith	5	18	49	80	111	133	118	103	88	74	59	5	17	47	75	101	118	103	88	74	60	47
Somervell	287	184	260	336	413	372	330	289	248	207	165	264	155	195	244	289	251	215	181	149	119	91
Starr	36	48	64	79	79	69	59	49	39	29	18	29	36	40	49	48	41	35	28	22	16	10
Stephens	0	52	184	315	447	402	357	312	268	223	179	0	44	138	229	313	271	232	195	161	128	98
Sterling	57	265	707	881	893	905	765	625	484	344	236	39	141	248	303	302	300	249	199	151	105	71
Stonewall	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sutton	34	0	390	534	677	821	730	639	547	456	365	23	0	137	183	229	272	237	204	171	140	109
Swisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tarrant	8,805	6,836	5,469	4,101	2,734	1,367	0	0	0	0	0	8,101	5,773	4,102	2,974	1,914	923	0	0	0	0	0
Taylor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Terrell	10	0	162	221	281	341	303	265	227	189	151	7	0	57	76	95	113	98	84	71	58	45
Terry	3	0	243	332	422	511	454	397	341	284	227	2	0	85	114	142	169	148	127	106	87	68
Throckmorton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Titus	3	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Tom Green	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Travis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trinity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tyler	76	110	147	184	185	161	137	114	90	66	42	72	83	93	114	113	96	80	65	50	36	23
Upshur	4	57	247	437	627	764	690	617	543	469	396	4	54	226	393	555	665	591	519	449	382	316
Upton	1,761	2,955	3,728	3,442	3,156	2,870	2,398	1,927	1,455	983	664	1,198	1,576	1,305	1,171	1,041	916	749	588	433	283	185
Uvalde	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Val Verde	0	0	80	110	139	168	150	131	112	94	75	0	0	28	38	47	56	49	42	35	29	22
Van Zandt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Victoria	0	35	46	58	58	51	43	36	28	21	14	0	26	29	36	35	30	25	20	16	11	7
Walker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Waller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ward	568	568	683	888	871	855	764	672	581	489	398	114	568	239	297	278	260	228	197	167	138	110
Washington	36	0	497	878	798	718	638	559	479	399	319	29	0	298	516	459	404	351	300	251	204	160
Webb	4,596	3,661	3,476	3,052	2,626	2,244	1,872	1,501	1,128	699	255	3,677	2,627	2,109	1,814	1,529	1,274	1,033	803	580	344	113
Wharton	0	43	57	71	72	62	53	44	35	26	17	0	32	36	44	43	37	31	25	20	14	9
Wheeler	3,792	3,524	3,072	2,620	2,168	1,717	1,265	813	362	0	0	1,896	1,605	1,229	1,015	813	622	443	274	117	0	0
Wichita	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilbarger	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Willacy	0	23	31	39	39	34	29	24	19	14	9	0	18	20	24	24	20	17	14	11	8	5
Williamson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilson	417	1,612	1,865	1,679	1,492	1,306	1,119	932	746	560	373	334	1,146	1,119	986	858	734	615	501	392	287	187
Winkler	62	464	618	821	1,024	979	873	767	661	556	450	12	247	216	275	332	305	267	231	195	160	127
Wise	2,314	2,757	2,450	2,144	1,838	1,531	1,225	919	613	306	0	2,129	2,328	1,838	1,555	1,287	1,034	796	574	368	176	0
Wood	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Yoakum	18	238	330	423	384	346	308	269	230	192	154	13	127	116	145	130	115	100	86	72	59	46
Young	8	0	78	157	235	211	188	164	141	118	94	7	0	59	113	164	143	122	103	85	68	52
Zapata	32	41	55	68	68	60	51	42	33	25	16	26	31	35	42	42	35	30	24	19	13	8
Zavala	407	2,065	2,427	2,280	2,167	2,035	1,904	1,773	1,502	1,197	891	326	1,477	1,465	1,351	1,247	1,132	1,020	912	747	575	410
SUM (kAF)	**81.5**	**110**	**132**	**135**	**134**	**122**	**104**	**87**	**70**	**53**	**39**	**64.8**	**78.2**	**76.9**	**76.0**	**72.8**	**64.2**	**53.2**	**43.4**	**34.4**	**26.3**	**19.1**

MiningWaterUse2010-2060_5.xls

Table 16. County-level estimate of 2012-2060 projections for oil and gas water use and water consumption (AF).

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Anderson	39	129	140	157	177	181	185	169	147	126	105	67	87	88	98	109	115	121	109	93	78	63
Andrews	3,212	3,481	3,959	3,833	3,710	3,511	3,177	2,842	2,509	2,192	1,929	1,868	1,231	1,029	921	819	742	640	544	453	372	311
Angelina	0	116	220	316	412	427	389	351	312	274	237	32	112	203	286	366	374	336	299	263	228	195
Aransas	0	12	10	8	7	5	5	5	5	5	5	10	11	10	8	6	5	5	5	5	5	5
Archer	30	351	405	444	483	389	344	311	279	246	213	239	326	337	343	344	252	222	194	167	142	119
Armstrong	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Atascosa	1,012	2,993	2,770	2,713	2,706	2,700	2,693	2,393	2,021	1,649	1,279	867	2,155	1,711	1,618	1,551	1,484	1,415	1,219	1,000	790	590
Austin	0	28	127	224	320	288	257	226	194	163	132	20	29	88	143	195	173	151	130	110	91	73
Bailey	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bandera	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bastrop	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Baylor	1	14	14	14	14	14	13	13	13	13	13	12	12	12	12	12	12	12	12	12	13	13
Bee	66	111	127	129	112	95	80	67	53	40	26	92	90	89	87	74	62	52	44	36	28	20
Bell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bexar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blanco	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Borden	27	272	679	926	927	929	784	639	494	352	244	72	165	263	339	331	323	267	214	164	117	82
Bosque	0	470	557	627	696	579	516	466	416	365	315	238	439	462	485	502	387	340	296	255	216	180
Bowie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brazoria	0	91	102	113	125	114	100	88	76	64	52	42	80	78	82	86	76	67	59	52	45	38
Brazos	238	364	741	975	1,207	1,072	938	804	670	536	402	266	286	477	602	721	628	538	451	368	287	211
Brewster	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brooks	27	70	77	84	80	69	60	52	44	36	28	50	60	58	60	55	47	41	36	31	26	22
Brown	23	35	34	34	33	32	31	30	29	28	27	17	16	14	14	14	14	14	14	14	14	14
Burleson	247	380	995	1,459	1,923	1,717	1,512	1,306	1,100	892	686	279	299	632	890	1,135	993	855	723	595	471	354
Burnet	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Caldwell	75	98	123	111	98	85	72	59	46	33	20	82	75	81	71	62	54	45	37	29	22	14
Calhoun	18	48	52	57	55	47	41	35	30	25	19	34	41	39	41	38	32	28	24	21	18	15
Callahan	84	93	88	88	87	83	79	74	70	66	62	29	24	18	17	16	15	15	15	15	15	15
Cameron	27	58	65	72	68	57	47	39	31	23	15	38	47	45	48	43	34	28	23	18	13	9
Camp	13	12	12	11	11	11	10	9	9	8	8	2	2	1	1	1	0	0	0	0	0	0
Carson	2	14	14	14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13	13	13	13
Cass	1	30	39	48	58	68	60	52	45	37	30	26	28	36	44	52	60	52	45	38	31	24
Castro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chambers	0	9	9	9	9	9	9	9	9	9	9	8	9	9	9	9	9	9	9	9	9	9
Cherokee	10	129	172	216	263	299	267	236	204	173	141	80	123	163	201	239	269	236	204	173	144	116
Childress	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clay	63	508	613	699	786	655	584	527	471	414	357	318	472	506	538	563	435	382	333	286	243	202
Cochran	56	128	154	181	208	234	210	187	163	139	115	46	64	54	63	71	79	70	62	54	46	38
Coke	520	511	484	480	477	451	425	397	370	346	322	114	84	46	40	33	32	31	29	28	27	26
Coleman	100	113	108	107	107	102	97	91	86	82	77	37	31	24	23	22	21	21	21	21	21	20
Collin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colorado	28	129	608	1,078	1,534	1,376	1,221	1,067	913	759	605	86	120	402	667	913	802	697	596	499	406	317
Comal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Comanche	2	388	444	485	525	419	363	319	276	232	188	224	366	374	379	380	278	240	204	170	138	109
Concho	515	507	480	477	474	448	422	394	367	343	320	114	84	46	40	34	33	31	30	29	28	27
Cooke	1,493	1,708	1,343	978	612	246	28	27	26	25	24	1,391	1,434	1,001	702	421	158	13	13	13	13	13
Coryell	0	569	1,238	1,102	767	434	158	0	0	0	0	236	522	972	827	548	284	103	0	0	0	0

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Cottle	32	43	41	41	41	39	38	36	34	33	31	18	16	14	14	13	13	13	13	13	13	13
Crane	280	508	617	728	840	947	861	776	692	610	531	227	246	225	249	273	299	265	232	201	174	149
Crockett	507	1,097	1,732	2,035	1,843	1,552	1,261	971	682	394	207	553	606	641	730	650	539	434	332	235	143	85
Crosby	1,083	1,050	994	987	980	926	871	814	757	706	656	224	161	82	69	55	53	50	47	45	43	40
Culberson	279	293	506	873	1,240	1,535	1,393	1,250	1,110	972	843	151	97	249	308	371	415	368	323	279	240	208
Dallam	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dallas	79	726	1,076	888	700	512	339	170	0	0	0	134	624	818	651	493	343	220	106	0	0	0
Dawson	268	695	954	1,137	1,164	1,184	1,023	862	703	546	423	165	323	328	371	360	353	296	241	189	140	104
Deaf Smith	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Delta	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Denton	3,249	3,297	2,220	1,136	51	19	13	13	13	13	13	3,108	2,805	1,688	840	44	13	13	13	13	13	13
DeWitt	2,177	2,061	1,858	1,646	1,421	1,188	958	729	500	271	42	1,801	1,493	1,149	999	846	694	550	413	281	155	35
Dickens	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	13
Dimmit	3,708	4,874	4,919	5,001	5,001	4,952	4,337	3,580	2,824	2,068	1,315	3,068	3,506	2,980	2,913	2,795	2,648	2,246	1,797	1,368	958	569
Donley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Duval	52	133	147	160	153	131	114	99	84	69	54	96	114	110	114	105	89	77	68	58	50	41
Eastland	333	578	937	1,091	934	764	644	535	425	318	211	286	303	539	619	472	335	263	196	133	75	21
Ector	845	1,144	1,537	1,612	1,690	1,628	1,435	1,245	1,056	870	725	850	612	588	577	570	520	447	377	310	251	206
Edwards	0	28	29	29	29	29	29	29	29	29	29	28	28	29	29	29	29	29	29	29	29	29
Ellis	38	112	147	180	213	186	164	144	123	103	82	56	99	114	133	150	125	107	90	74	59	45
El Paso	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Erath	12	470	505	521	536	426	376	340	304	268	232	274	443	427	411	391	283	250	218	188	161	134
Falls	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fannin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fayette	132	1,149	2,403	2,164	1,887	1,585	1,282	979	677	375	72	166	844	1,476	1,306	1,118	922	733	551	377	210	51
Fisher	432	426	403	401	398	376	355	332	309	289	269	97	71	40	35	30	28	27	26	25	24	24
Floyd	148	156	148	147	146	139	131	123	116	109	102	42	34	23	21	19	19	19	18	18	18	17
Foard	3	12	12	12	12	12	12	12	12	12	11	10	10	10	10	10	10	10	10	10	10	10
Fort Bend	25	66	72	79	75	65	56	49	41	34	27	47	56	54	56	52	44	38	33	29	24	20
Franklin	5	5	5	5	5	5	4	4	4	3	3	1	1	0	0	0	0	0	0	0	0	0
Freestone	429	929	1,117	1,331	1,494	1,458	1,291	1,121	954	785	618	600	844	975	1,133	1,254	1,213	1,056	903	757	615	479
Frio	729	1,167	1,217	1,243	1,250	1,215	1,178	1,142	986	804	620	666	858	772	774	752	702	652	603	504	398	296
Gaines	124	914	1,429	1,846	2,000	1,945	1,671	1,398	1,127	859	651	190	517	590	686	694	635	533	436	344	259	197
Galveston	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Garza	53	321	395	469	544	491	438	386	334	284	234	44	166	144	164	184	162	142	122	104	87	71
Gillespie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glasscock	1,838	2,402	3,057	2,887	2,718	2,355	1,994	1,634	1,275	921	681	1,590	1,165	1,010	923	839	704	575	452	334	224	153
Goliad	25	64	70	77	73	63	54	47	40	33	26	46	55	53	55	50	42	37	32	28	24	20
Gonzales	2,164	1,791	1,600	1,405	1,207	1,010	813	616	418	221	24	1,764	1,288	980	844	712	585	463	346	233	126	23
Gray	68	78	75	74	74	70	67	63	60	57	53	26	22	17	16	15	15	15	15	15	15	15
Grayson	6	19	18	18	18	18	18	18	17	17	17	14	14	14	14	14	14	14	14	14	14	14
Gregg	25	191	274	353	433	476	429	383	337	292	246	71	182	256	322	387	418	371	326	282	240	199
Grimes	95	159	323	483	602	537	471	405	340	275	209	120	129	214	305	367	321	276	233	192	153	115
Guadalupe	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Hale	1,289	1,235	1,168	1,160	1,152	1,087	1,022	954	886	826	766	252	177	82	67	51	48	45	42	39	36	33
Hall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hamilton	0	361	393	314	236	157	101	51	0	0	0	93	321	312	239	169	103	66	32	0	0	0
Hansford	13	88	577	1,068	904	749	602	456	309	162	16	68	79	261	432	348	278	218	161	108	59	13
Hardeman	0	9	9	9	9	10	10	10	10	10	10	9	9	9	9	9	10	10	10	10	10	10
Hardin	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Harris	0	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Harrison	868	1,763	2,388	2,145	1,956	1,778	1,608	1,438	1,268	1,098	930	1,021	1,658	2,189	1,935	1,735	1,557	1,386	1,219	1,059	903	753

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Hartley	7	7	7	7	7	6	6	6	5	5	4	1	1	0	0	0	0	0	0	0	0	0
Haskell	90	98	93	93	92	88	83	79	74	70	66	30	25	18	17	16	16	15	15	15	15	15
Hays	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hemphill	1,441	2,567	2,314	2,037	1,763	1,499	1,244	988	732	476	223	1,498	1,209	971	821	683	562	452	349	252	163	80
Henderson	3	120	176	235	296	346	308	272	235	198	161	91	113	166	218	269	310	272	235	199	164	131
Hidalgo	46	119	130	143	136	117	101	88	74	61	48	85	101	98	102	94	79	69	60	52	44	37
Hill	131	1,572	1,343	1,106	869	632	422	218	13	14	14	244	1,349	1,031	819	617	427	279	141	13	14	14
Hockley	6	18	18	18	18	17	17	17	17	16	16	13	13	13	13	13	13	13	13	13	13	13
Hood	645	529	678	820	961	841	743	651	559	467	375	695	465	528	608	679	566	485	409	338	271	209
Hopkins	42	41	38	38	38	36	34	31	29	27	25	8	6	3	2	2	2	1	1	1	1	1
Houston	178	254	322	287	254	220	187	152	119	85	51	195	196	210	185	161	138	116	94	74	54	35
Howard	619	1,611	2,491	2,939	2,747	2,343	1,940	1,538	1,138	742	476	643	870	898	1,028	938	782	633	490	354	226	142
Hudspeth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hutchinson	21	51	156	237	204	173	144	115	86	58	30	32	34	85	110	90	75	62	50	39	28	20
Irion	1,677	2,286	3,192	3,643	3,357	2,890	2,423	1,955	1,487	1,026	713	1,070	937	937	1,065	940	778	621	471	327	190	102
Jack	17	501	575	635	693	572	499	438	378	317	256	232	459	470	487	497	381	328	278	231	187	146
Jackson	25	64	70	77	73	63	55	47	40	33	26	46	55	53	55	51	43	37	32	28	24	20
Jasper	87	118	148	133	118	103	88	73	58	43	28	100	92	98	88	77	67	57	47	38	30	21
Jeff Davis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jefferson	0	13	13	13	13	14	14	14	14	14	14	13	13	13	13	13	14	14	14	14	14	14
Jim Hogg	33	85	93	102	97	83	72	63	53	44	34	61	73	70	73	67	56	49	43	37	31	26
Jim Wells	25	65	71	78	74	64	55	48	40	33	26	46	55	53	55	51	43	37	33	28	24	20
Johnson	4,192	4,240	3,530	2,809	2,086	1,365	683	10	10	10	10	4,029	3,611	2,680	2,059	1,471	918	447	10	10	10	10
Jones	117	125	119	118	117	111	106	99	93	88	82	35	29	20	19	17	17	17	16	16	16	16
Karnes	3,882	2,820	2,528	2,229	1,919	1,603	1,288	975	662	349	35	3,155	2,028	1,545	1,336	1,127	923	728	542	363	192	29
Kaufman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kendall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kenedy	42	108	118	130	123	106	92	80	68	55	43	78	92	89	92	85	72	62	55	47	40	33
Kent	29	39	38	38	38	36	35	33	32	31	29	18	16	14	14	13	13	13	13	13	13	13
Kerr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kimble	0	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
King	8,635	8,287	7,836	7,783	7,730	7,293	6,857	6,402	5,946	5,545	5,144	1,704	1,198	565	461	357	334	311	291	271	253	236
Kinney	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kleberg	27	70	77	84	80	69	60	52	44	36	28	51	60	58	60	55	47	41	36	31	26	22
Knox	3	15	15	15	15	14	14	14	14	14	14	12	12	12	12	12	12	12	12	12	12	12
Lamar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamb	647	620	586	582	579	546	513	479	445	415	385	127	89	41	34	26	24	22	21	19	18	17
Lampasas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
La Salle	2,889	4,569	4,617	4,705	4,772	4,830	4,263	3,541	2,819	2,098	1,380	2,408	3,293	2,801	2,731	2,647	2,556	2,183	1,757	1,349	959	590
Lavaca	145	1,003	1,613	1,470	1,313	1,148	985	824	662	501	340	179	742	1,005	898	786	673	567	465	368	274	184
Lee	132	230	421	536	650	577	506	435	363	290	218	151	179	272	333	390	340	292	246	201	158	117
Leon	327	847	1,482	1,983	2,481	2,349	2,077	1,802	1,530	1,256	985	361	629	977	1,301	1,611	1,527	1,325	1,129	941	758	584
Liberty	0	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Limestone	271	383	402	424	431	391	347	302	257	212	167	356	350	355	363	361	325	283	242	203	166	129
Lipscomb	387	656	1,098	926	758	597	446	294	142	21	21	434	335	467	375	290	221	161	105	52	13	13
Live Oak	1,002	851	814	751	757	776	798	820	729	610	492	853	627	523	473	455	443	433	422	363	294	230
Llano	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loving	542	691	792	925	1,058	1,020	934	848	762	681	601	300	256	223	251	279	259	229	202	175	152	131
Lubbock	6,211	5,963	5,663	5,673	5,684	5,419	5,089	4,745	4,401	4,097	3,794	1,228	865	433	365	298	290	268	249	229	212	196
Lynn	981	974	1,166	1,246	1,327	1,365	1,255	1,144	1,033	929	826	226	168	179	192	205	227	200	175	150	128	107
McCulloch	42	40	38	38	38	35	33	31	29	27	25	8	6	3	2	2	2	1	1	1	1	1

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
McLennan	0	194	234	265	296	235	203	177	152	127	101	119	185	197	206	212	154	132	111	91	73	56
McMullen	1,720	2,653	2,912	3,203	3,448	3,666	3,398	3,010	2,622	2,235	1,850	1,465	1,924	1,775	1,860	1,911	1,941	1,746	1,507	1,276	1,056	848
Madison	204	295	597	785	972	861	754	646	538	430	323	227	231	384	485	581	504	432	362	295	231	169
Marion	5	208	348	483	619	622	561	501	440	379	319	73	196	322	438	552	546	485	425	368	312	258
Martin	2,435	2,906	3,527	3,262	2,998	2,657	2,251	1,845	1,441	1,043	771	2,190	1,435	1,191	1,059	933	796	651	513	380	257	177
Mason	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Matagorda	34	87	96	105	100	86	75	64	55	45	35	63	75	72	75	69	58	51	44	38	32	27
Maverick	174	1,652	1,988	2,364	2,737	3,111	2,933	2,617	2,302	1,986	1,674	188	1,196	1,201	1,342	1,474	1,597	1,461	1,269	1,085	910	744
Medina	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Menard	1,185	1,148	1,086	1,079	1,071	1,012	952	889	827	772	717	244	175	88	74	59	56	53	50	48	45	43
Midland	1,719	2,876	3,522	3,272	3,025	2,666	2,227	1,788	1,350	918	612	1,661	1,506	1,256	1,127	1,005	855	695	542	395	257	164
Milam	0	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Mills	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mitchell	27	284	361	435	511	460	409	358	309	259	211	50	162	142	163	184	162	141	122	103	86	70
Montague	3,233	3,776	3,228	2,665	2,102	1,538	1,026	525	25	24	24	3,186	3,216	2,452	1,950	1,474	1,025	663	326	14	14	14
Montgomery	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Moore	4	16	16	16	16	16	16	15	15	15	15	13	13	13	12	12	12	13	13	13	13	13
Morris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Motley	130	138	132	131	130	123	117	110	103	97	91	39	31	22	20	19	18	18	18	18	17	17
Nacogdoches	1,073	1,642	2,299	2,141	1,986	1,815	1,643	1,471	1,299	1,128	958	1,220	1,550	2,101	1,930	1,764	1,591	1,420	1,251	1,089	932	779
Navarro	11	25	24	24	24	24	23	23	22	22	21	17	16	15	15	15	15	15	15	15	15	15
Newton	98	138	173	156	138	120	102	84	67	49	31	111	107	115	102	89	77	65	54	43	33	23
Nolan	214	218	207	205	204	193	182	171	160	150	140	54	42	26	24	21	21	20	20	19	19	18
Nueces	25	64	70	77	73	63	55	47	40	33	26	46	55	53	55	51	43	37	32	28	24	20
Ochiltree	286	508	824	1,040	853	674	503	332	161	24	23	329	266	355	418	325	247	180	116	57	13	13
Oldham	15	14	13	13	13	12	12	11	10	9	9	3	2	1	1	1	1	1	0	0	0	0
Orange	0	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Palo Pinto	120	547	656	752	847	709	625	552	480	408	336	281	446	483	524	557	430	370	314	261	212	165
Panola	958	1,578	2,136	1,919	1,749	1,590	1,438	1,286	1,134	983	832	1,095	1,484	1,959	1,731	1,552	1,392	1,240	1,091	948	808	674
Parker	1,083	1,180	1,464	1,733	2,001	1,748	1,545	1,353	1,162	970	779	1,215	1,035	1,139	1,284	1,414	1,176	1,009	851	702	563	434
Parmer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pecos	409	543	690	878	1,068	1,180	1,072	966	861	762	672	274	227	313	331	353	359	320	283	249	220	198
Polk	133	195	247	221	195	170	144	118	92	67	41	148	151	162	143	125	107	90	74	58	43	29
Potter	2	14	14	14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13	13	13	13
Presidio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Randall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reagan	1,350	3,414	4,211	3,802	3,395	2,985	2,457	1,931	1,406	886	529	1,361	1,825	1,501	1,323	1,153	991	796	610	432	265	155
Real	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Red River	4	4	4	4	4	4	3	3	3	3	3	1	1	0	0	0	0	0	0	0	0	0
Reeves	611	1,111	1,520	2,067	2,619	2,761	2,522	2,285	2,052	1,827	1,614	701	632	688	796	908	888	791	700	615	541	477
Refugio	23	60	66	72	69	59	51	44	38	31	24	43	51	49	51	47	40	35	30	26	22	18
Roberts	365	1,711	1,502	1,270	1,041	822	611	400	189	20	20	423	819	647	524	412	316	231	151	76	20	20
Robertson	305	691	813	817	826	746	651	556	461	366	271	431	599	654	657	664	595	512	431	354	279	208
Rockwall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Runnels	285	287	272	271	269	255	240	225	210	197	184	70	53	32	29	26	25	24	24	23	22	22
Rusk	210	719	1,149	1,569	1,994	1,844	1,668	1,492	1,316	1,141	967	323	637	1,017	1,377	1,730	1,578	1,404	1,234	1,070	912	759
Sabine	147	331	584	809	1,035	946	858	770	682	595	508	196	319	536	728	915	826	739	653	571	491	413
San Augustine	1,584	2,198	2,077	1,928	1,779	1,628	1,479	1,330	1,180	1,032	884	1,642	2,052	1,880	1,722	1,567	1,415	1,268	1,124	983	847	715
San Jacinto	0	8	8	8	8	9	9	9	9	9	9	8	8	8	8	8	9	9	9	9	9	9
San Patricio	20	52	57	63	60	51	44	39	33	27	21	38	45	43	45	41	35	30	26	23	19	16

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
San Saba	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Schleicher	230	473	621	718	732	647	562	477	392	308	241	144	213	199	226	225	194	165	136	109	84	64
Scurry	3	34	280	368	456	544	483	423	363	304	246	37	33	118	143	169	193	168	145	123	102	83
Shackelford	219	464	562	655	747	628	558	500	442	385	328	264	285	329	373	409	305	263	224	187	153	121
Shelby	1,388	1,861	3,283	3,109	2,938	2,754	2,496	2,238	1,980	1,723	1,467	1,536	1,745	2,976	2,781	2,593	2,400	2,143	1,892	1,650	1,414	1,185
Sherman	9	42	35	121	207	178	151	124	98	71	44	28	33	26	55	84	70	59	48	39	29	21
Smith	20	91	107	125	145	163	147	131	115	100	84	67	71	85	100	117	132	117	102	88	74	61
Somervell	287	237	304	367	431	377	333	292	250	209	168	309	208	236	272	304	253	217	183	151	121	93
Starr	35	90	99	108	103	89	77	67	57	46	36	65	77	75	77	71	60	52	46	39	34	28
Stephens	5,158	5,248	5,064	5,103	5,141	4,775	4,458	4,141	3,825	3,541	3,257	1,226	1,004	663	630	591	476	423	374	328	285	244
Sterling	89	343	780	947	953	958	812	667	522	380	270	107	191	290	338	331	325	270	217	166	120	85
Stonewall	629	615	583	579	575	543	511	478	445	416	387	136	99	53	45	38	36	34	33	31	30	29
Sutton	33	59	446	582	720	858	763	668	573	481	389	81	53	185	225	264	303	264	227	192	160	130
Swisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tarrant	8,805	7,084	5,672	4,245	2,817	1,391	12	12	12	12	12	8,313	6,020	4,294	3,105	1,985	935	12	12	12	12	12
Taylor	71	81	77	77	76	73	69	65	62	58	55	26	22	17	16	15	15	15	15	15	15	14
Terrell	502	540	673	724	776	806	740	672	606	544	483	158	128	145	152	160	173	154	136	120	105	92
Terry	90	119	355	439	525	606	543	479	416	354	293	51	45	121	144	168	192	167	144	122	102	83
Throckmorton	200	204	194	193	191	181	171	161	150	141	132	52	40	25	23	20	20	19	19	19	18	18
Titus	8	8	7	7	7	7	6	6	5	5	5	2	1	1	0	0	0	0	0	0	0	0
Tom Green	53	72	69	69	68	66	63	60	58	55	53	31	28	24	24	23	23	23	23	23	23	23
Travis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trinity	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Tyler	78	123	160	197	198	174	150	127	103	79	55	91	96	106	127	125	109	93	78	63	49	36
Upshur	39	199	379	551	726	851	771	690	609	529	450	95	164	325	474	620	723	644	566	491	419	349
Upton	1,744	3,075	3,887	3,575	3,265	2,960	2,470	1,984	1,499	1,020	699	1,863	1,694	1,458	1,296	1,144	1,001	817	641	473	318	219
Uvalde	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Val Verde	0	66	144	169	195	221	199	179	158	139	120	67	66	91	97	102	108	98	89	81	74	68
Van Zandt	56	65	62	62	61	59	56	53	50	47	45	22	19	15	15	14	14	14	14	13	13	13
Victoria	25	66	72	79	75	65	56	49	41	34	27	47	56	54	56	52	44	38	33	29	24	20
Walker	0	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Waller	0	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Ward	582	632	775	968	941	915	815	716	617	521	429	622	620	317	362	333	307	267	229	193	161	132
Washington	0	44	545	924	840	757	673	589	506	422	338	30	46	346	561	500	442	385	330	277	227	178
Webb	4,599	3,878	3,708	3,257	2,804	2,397	2,007	1,623	1,238	796	341	3,948	2,844	2,337	2,014	1,701	1,422	1,166	922	687	439	196
Wharton	31	81	89	97	93	80	69	60	51	42	33	58	69	67	69	64	54	47	41	36	30	25
Wheeler	3,794	3,609	3,157	2,682	2,210	1,748	1,293	839	385	22	21	3,850	1,683	1,308	1,071	850	651	469	298	139	20	20
Wichita	59	65	62	62	61	58	55	52	49	46	44	20	17	12	12	11	11	11	11	10	10	10
Wilbarger	7	20	20	20	20	20	19	19	19	18	18	15	14	14	14	14	14	14	14	14	14	14
Willacy	17	44	49	53	51	44	38	33	28	23	18	32	38	37	38	35	29	26	22	19	17	14
Williamson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilson	418	1,671	1,929	1,740	1,548	1,357	1,165	973	782	590	399	373	1,206	1,182	1,045	912	783	659	540	426	315	210
Winkler	152	621	787	977	1,169	1,110	991	873	756	642	531	125	318	295	341	387	351	305	261	220	183	149
Wise	2,313	3,014	2,661	2,293	1,924	1,556	1,238	932	625	319	13	2,348	2,584	2,037	1,691	1,360	1,046	809	587	380	189	13
Wood	17	26	25	25	25	24	23	22	21	21	20	13	12	11	10	10	10	10	10	10	10	10
Yoakum	1,052	1,264	1,300	1,382	1,334	1,240	1,147	1,052	957	870	783	246	299	209	222	191	171	151	132	115	99	84
Young	15	142	197	244	291	236	206	183	159	135	111	125	136	165	188	208	156	135	116	97	81	65
Zapata	30	78	85	93	89	76	66	57	49	40	31	56	66	64	66	61	51	45	39	34	29	24
Zavala	407	2,140	2,531	2,379	2,257	2,118	1,977	1,838	1,559	1,245	932	409	1,555	1,570	1,448	1,336	1,212	1,092	975	802	622	450
SUM (kAF)	**118.4**	**159.3**	**178.4**	**179.6**	**175.1**	**159.9**	**139.0**	**119.1**	**99.6**	**81.4**	**65.4**	**92.7**	**96.4**	**91.8**	**88.0**	**82.0**	**71.3**	**59.7**	**49.4**	**39.8**	**31.3**	**23.8**

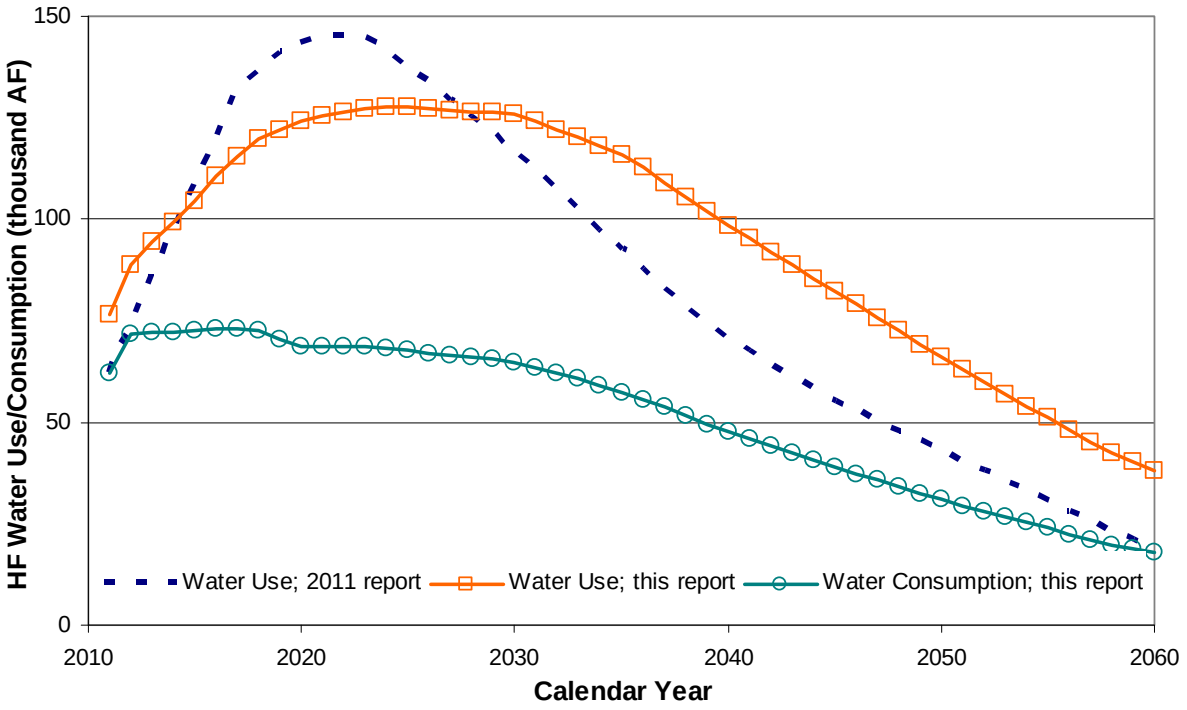


Figure 48. State-level projections to 2060 of HF water use and fresh-water consumption and comparison to earlier water projections.

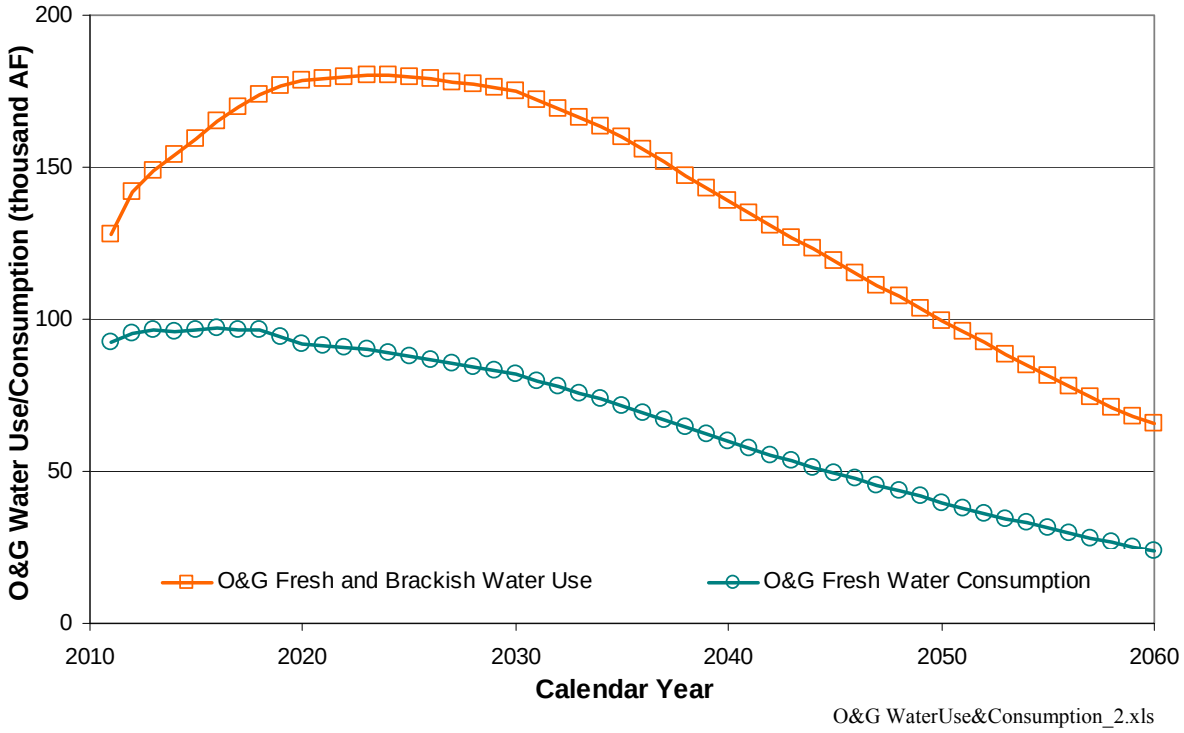


Figure 49. State-level projections to 2060 of oil and gas industry water use and fresh-water consumption.

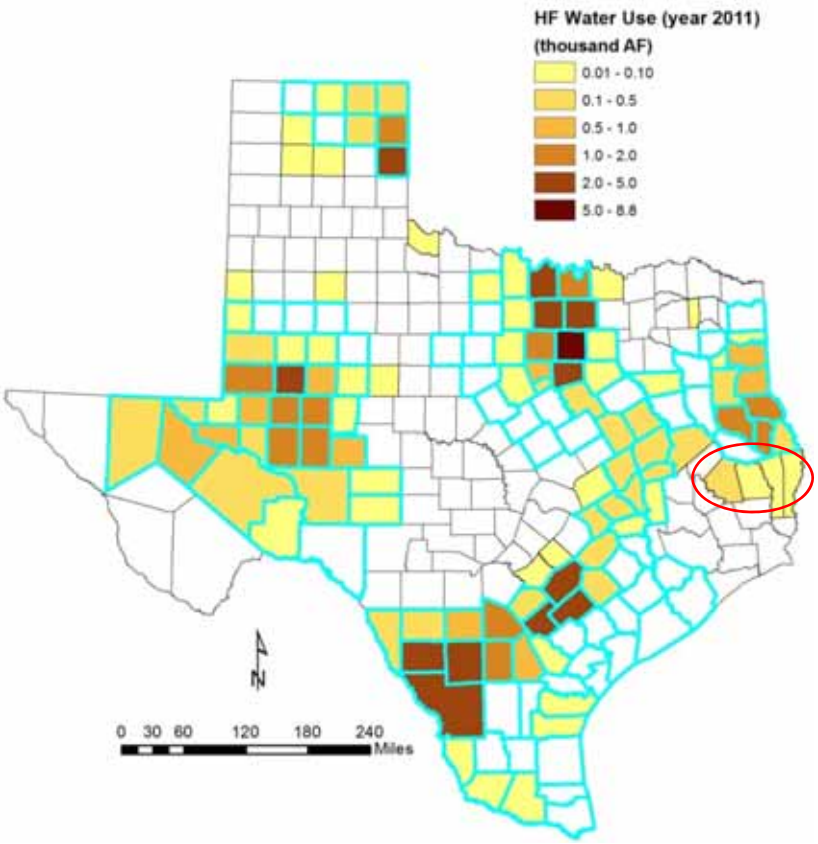
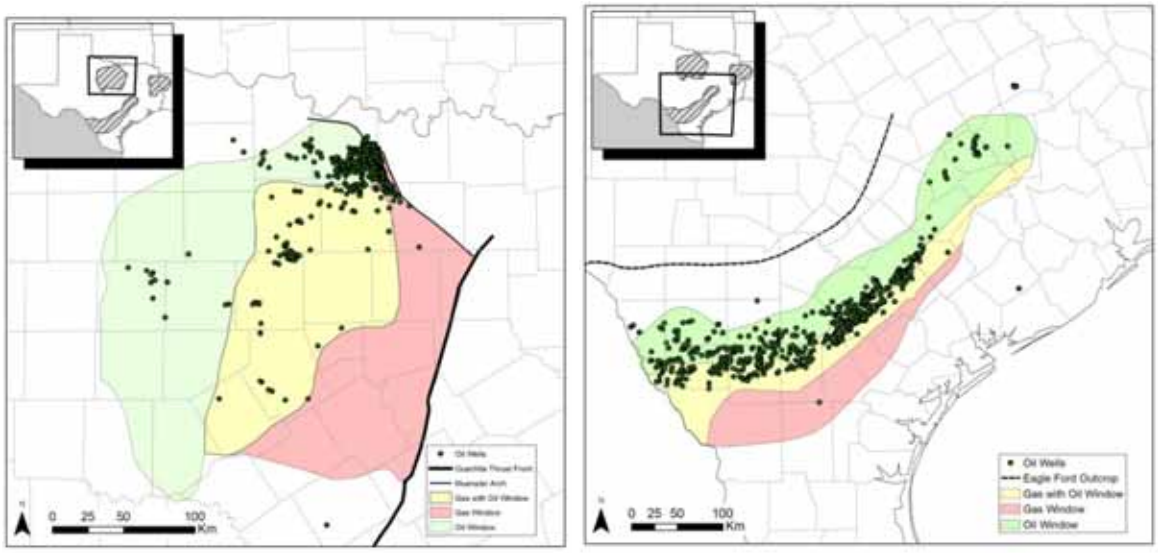
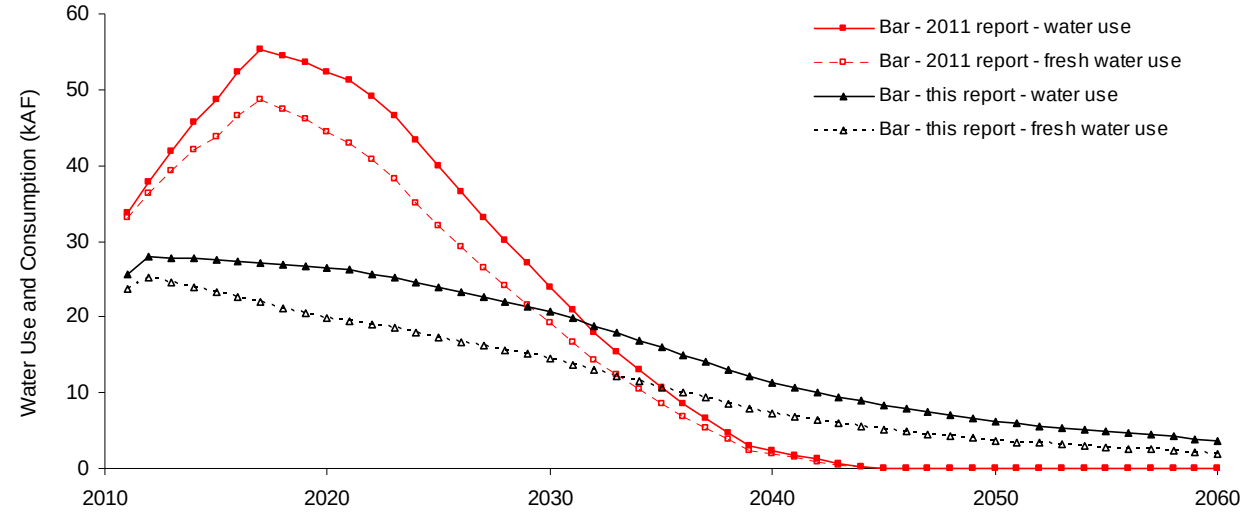


Figure 50. Counties with non-zero projected water use. Same coverage as in the 2011 report (thick blue lines) with the addition of Polk, Tyler, Jasper, and Newton counties in East Texas (red circle).

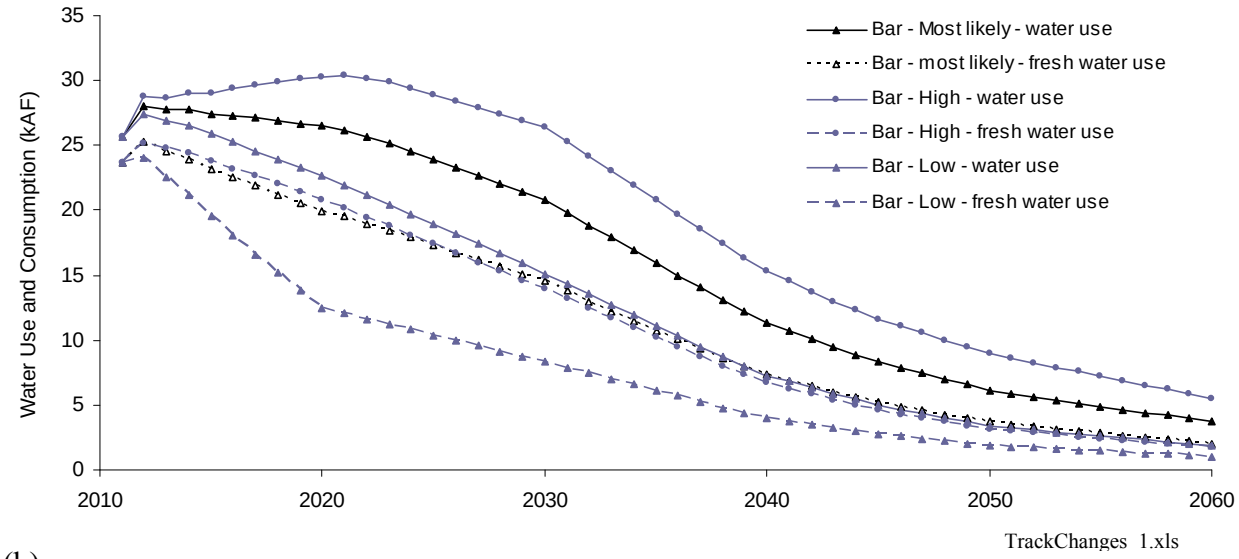


Source: Montgomery et al. (2005) Source: McMahon and Vaden (2011)

Figure 51. Spatial location of the oil and gas windows in the (a) Barnett Shale and (b) Eagle Ford Shale.

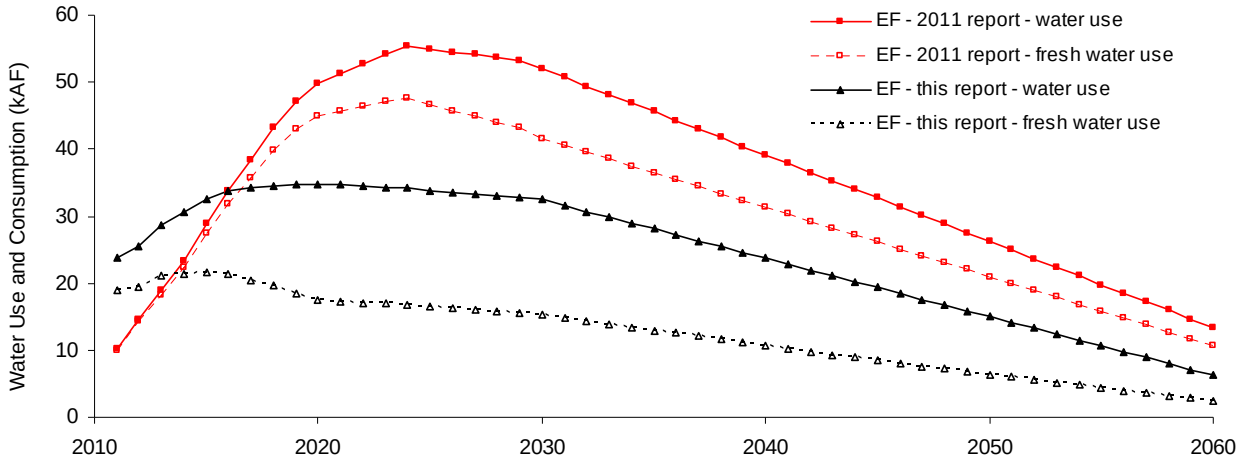


(a)

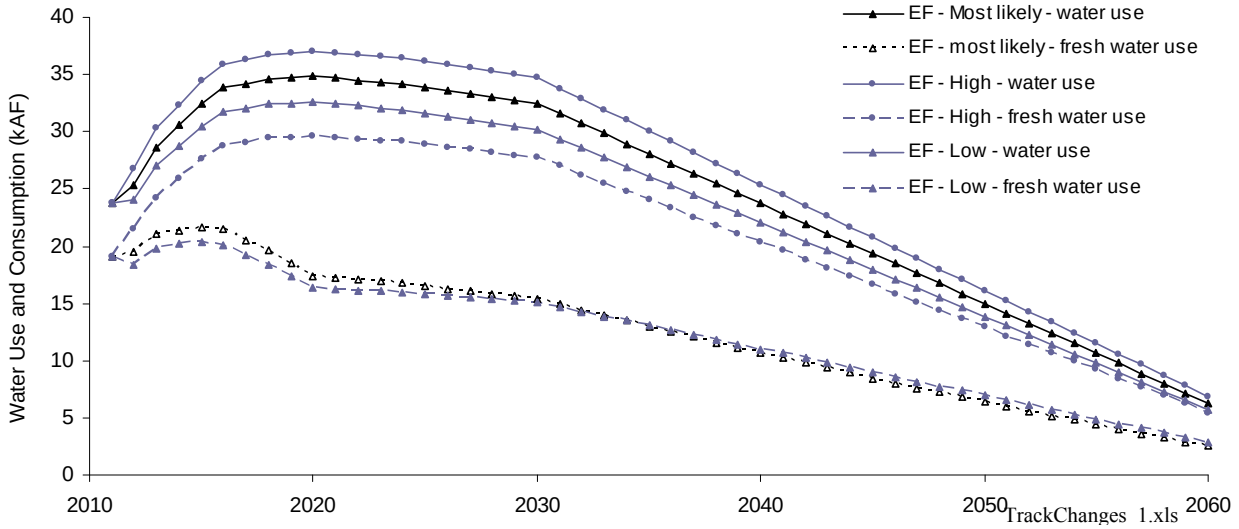


(b)

Figure 52. Barnett Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

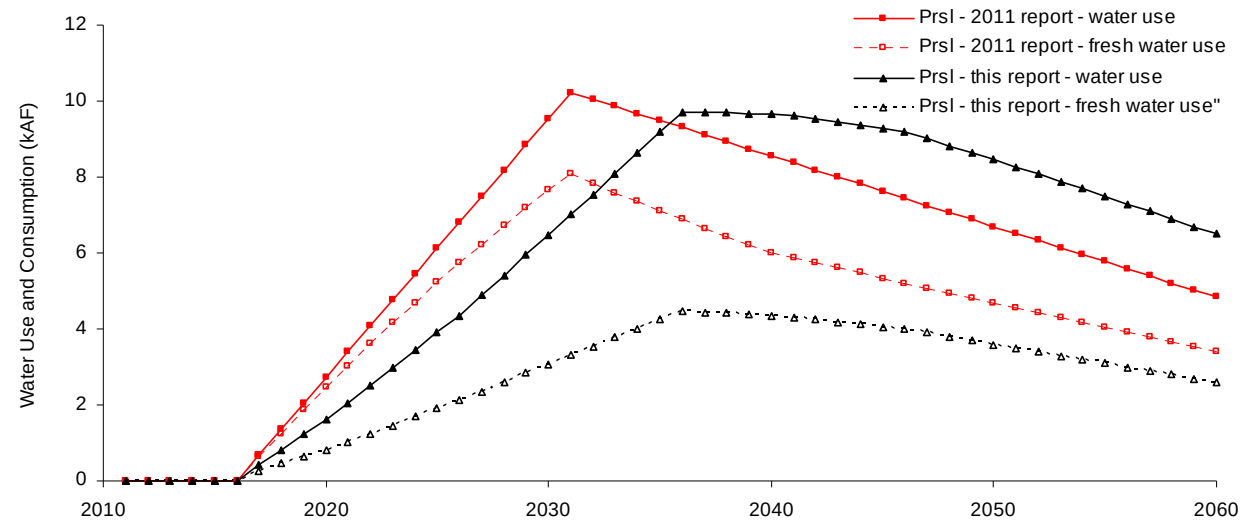


(a)

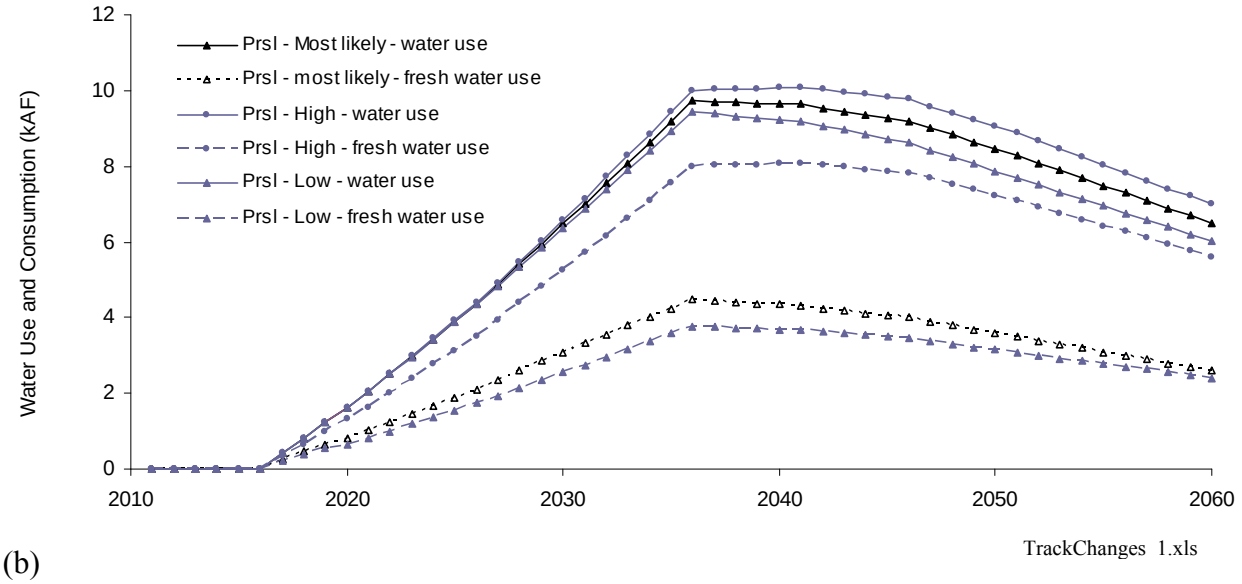


(b)

Figure 53. Eagle Ford Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

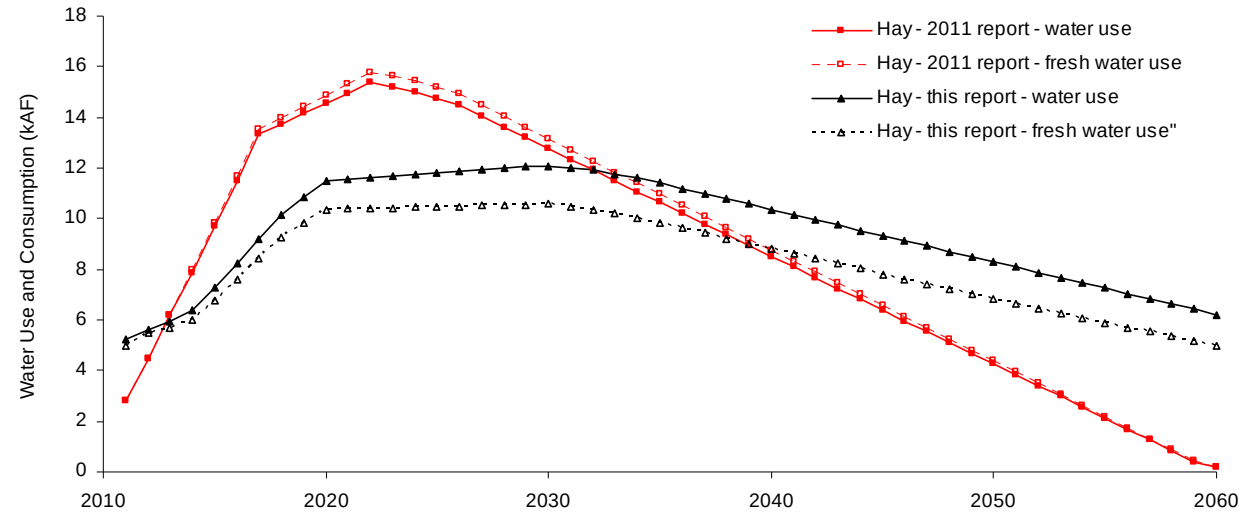


(a)

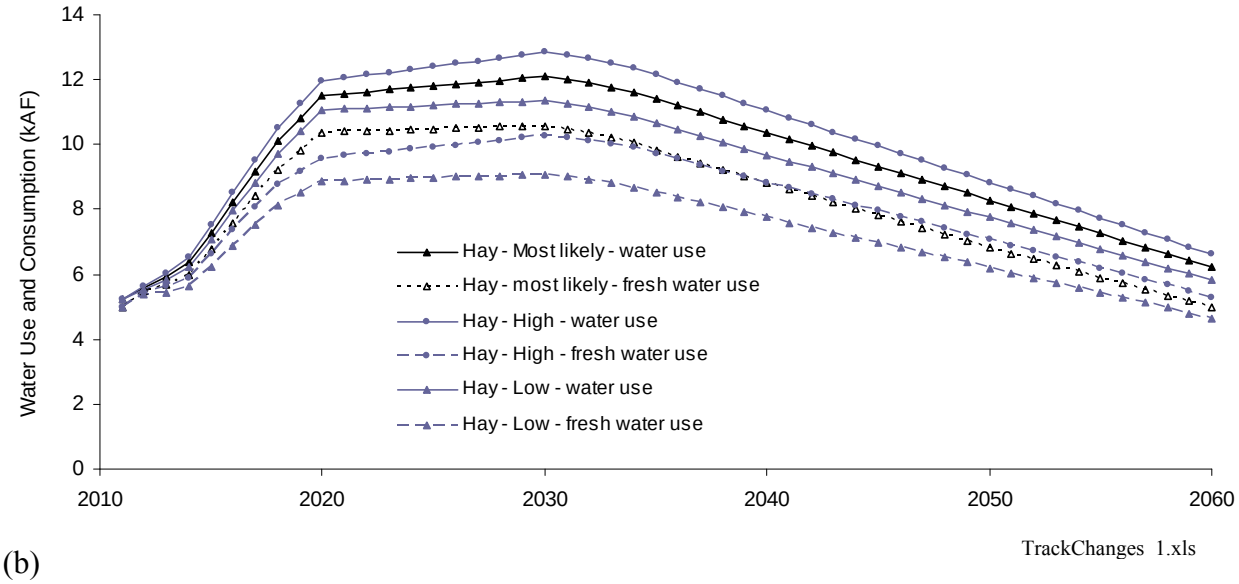


(b)

Figure 54. Pearsall Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

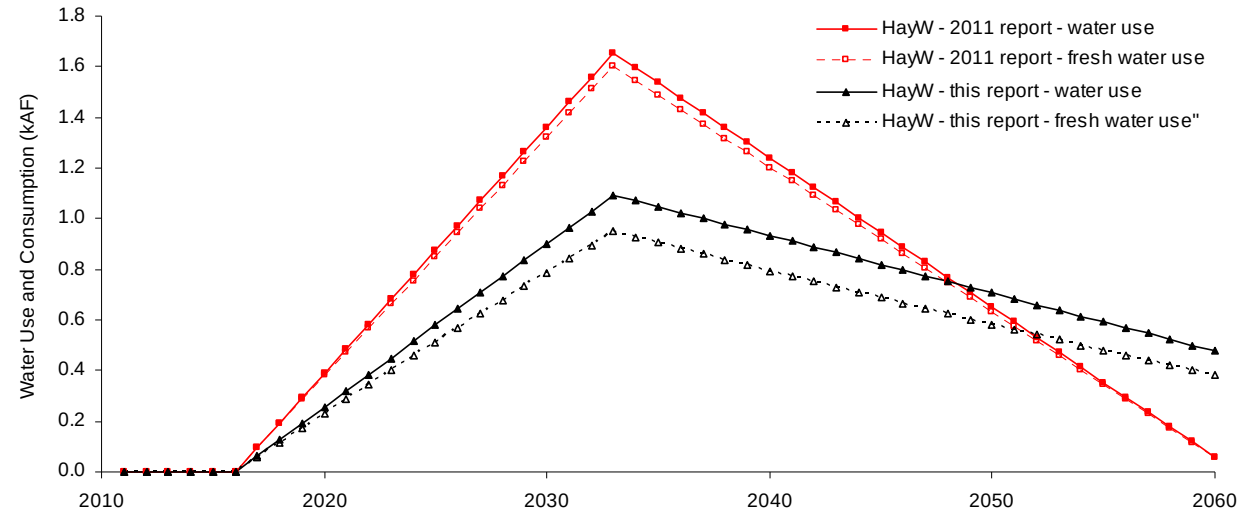


(a)

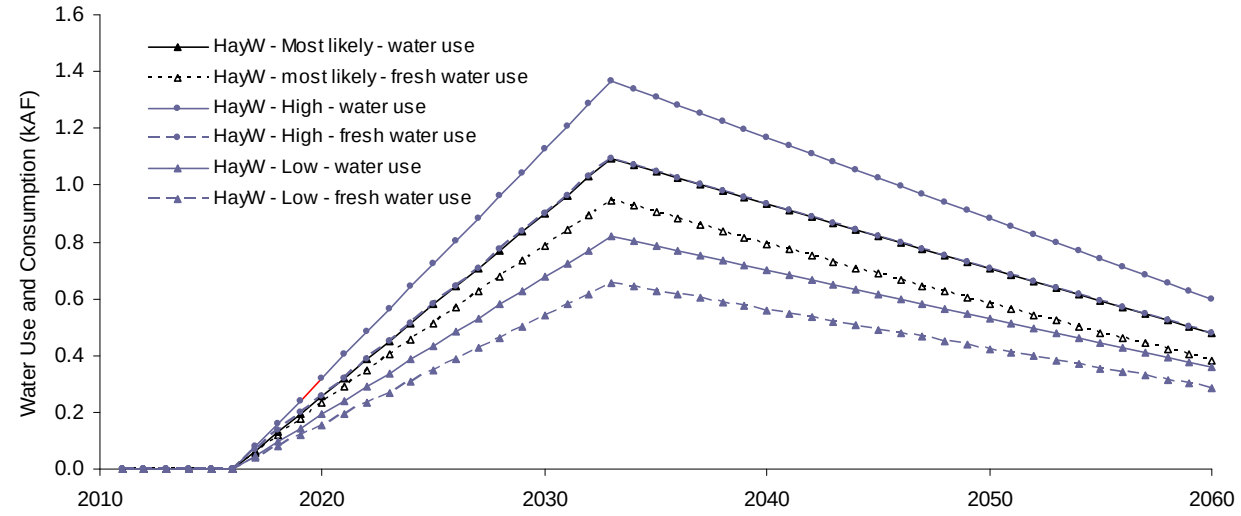


(b)

Figure 55. Haynesville and Bossier Shales water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

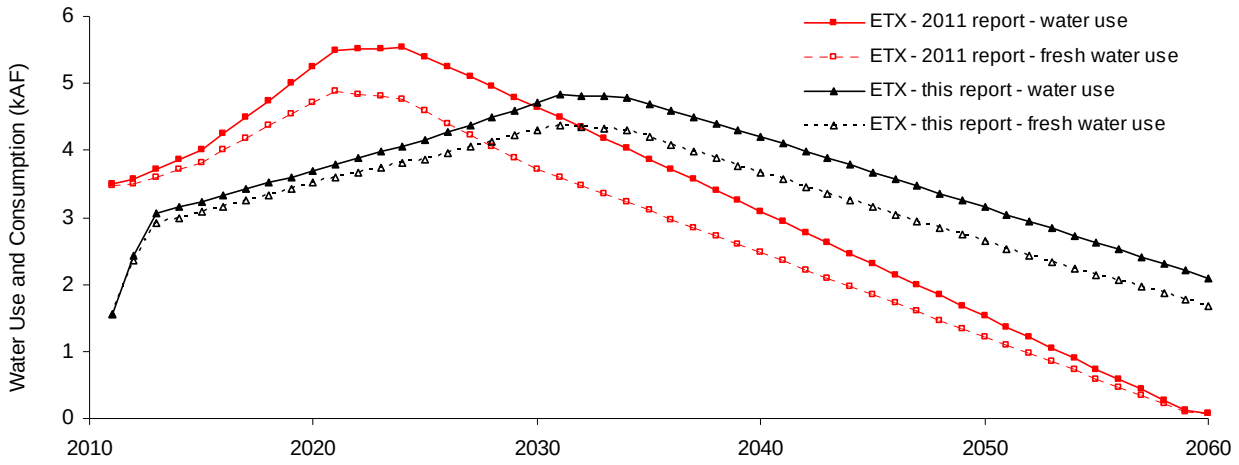


(a)

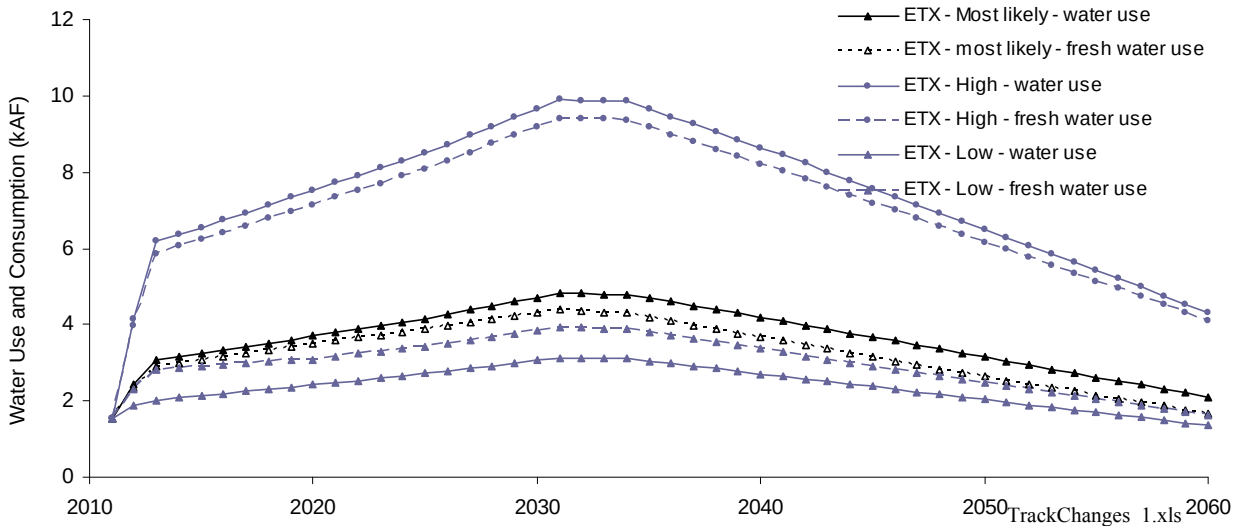


(b)

Figure 56. Haynesville-West Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

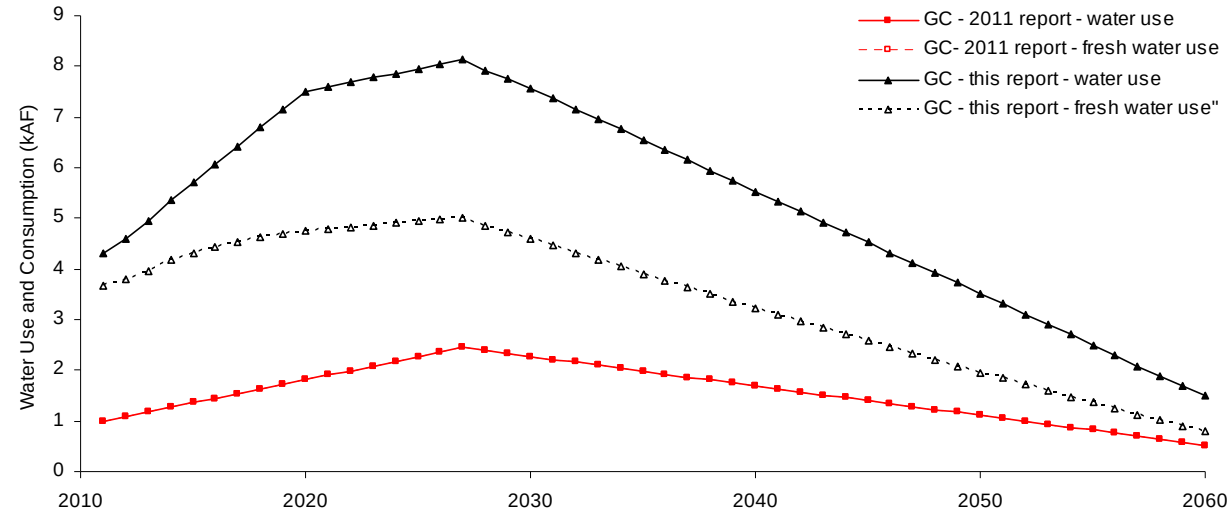


(a)

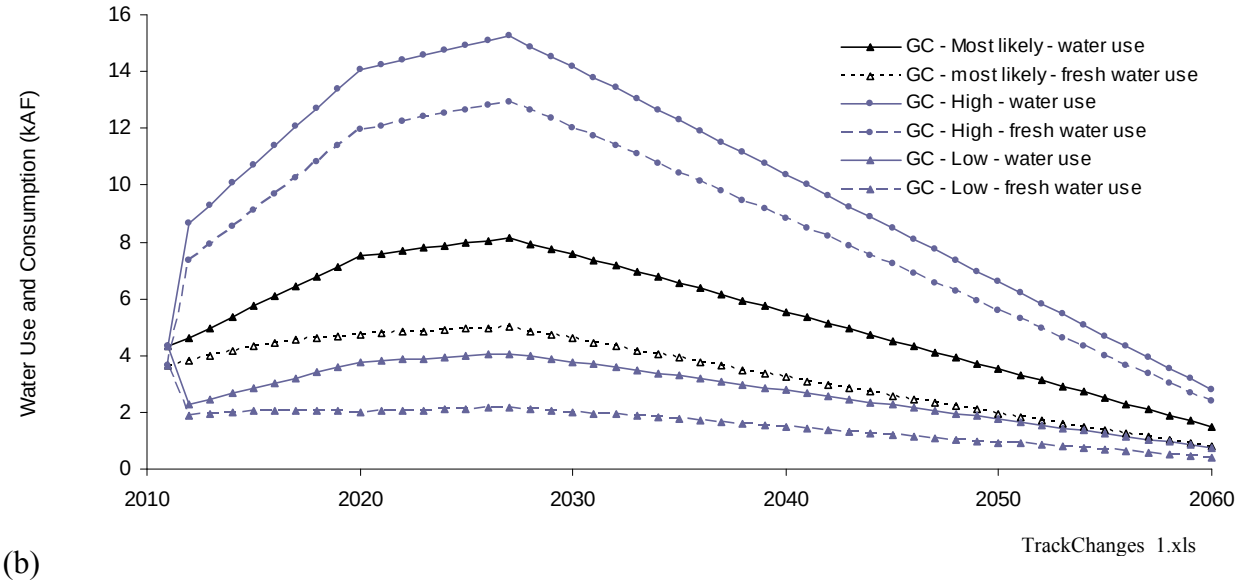


(b)

Figure 57. East Texas (not including Haynesville and Bossier Shales) water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

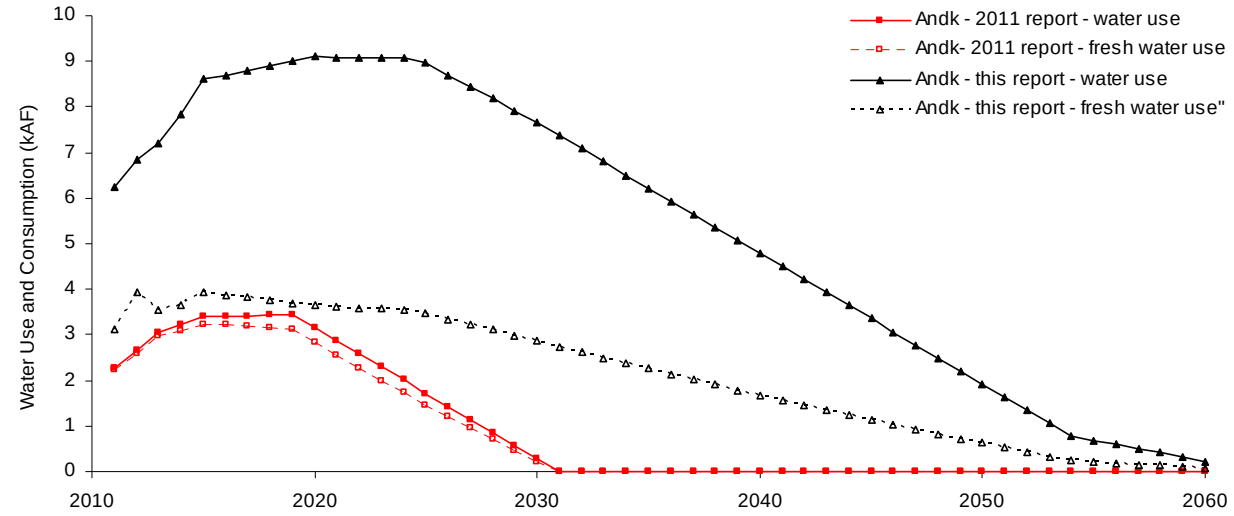


(a)

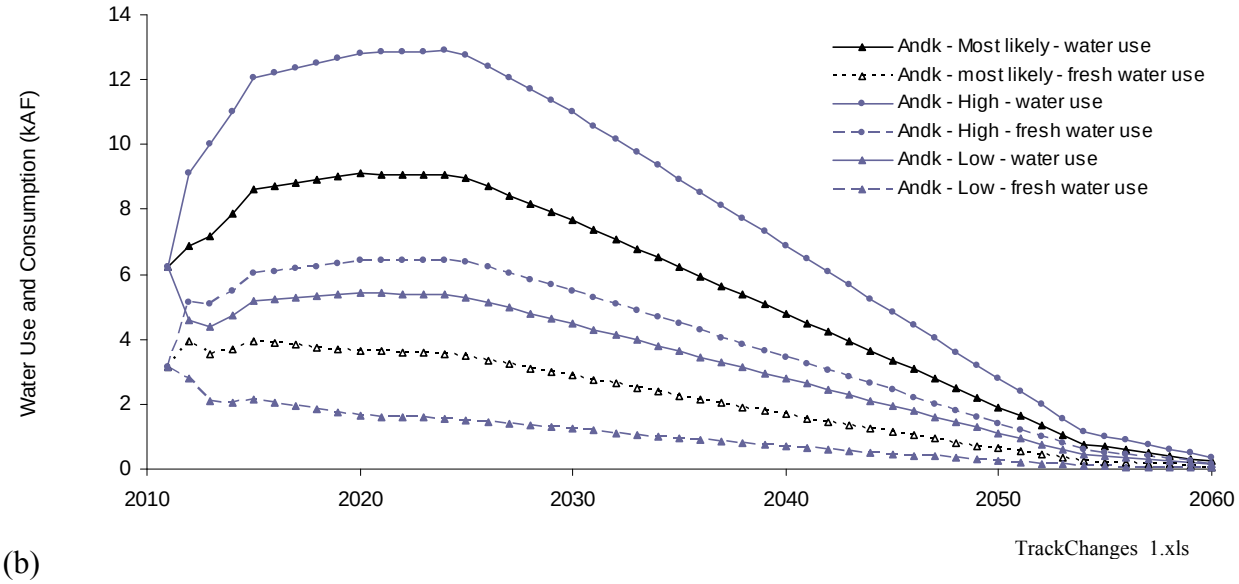


(b)

Figure 58. Gulf Coast (not including shales) water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

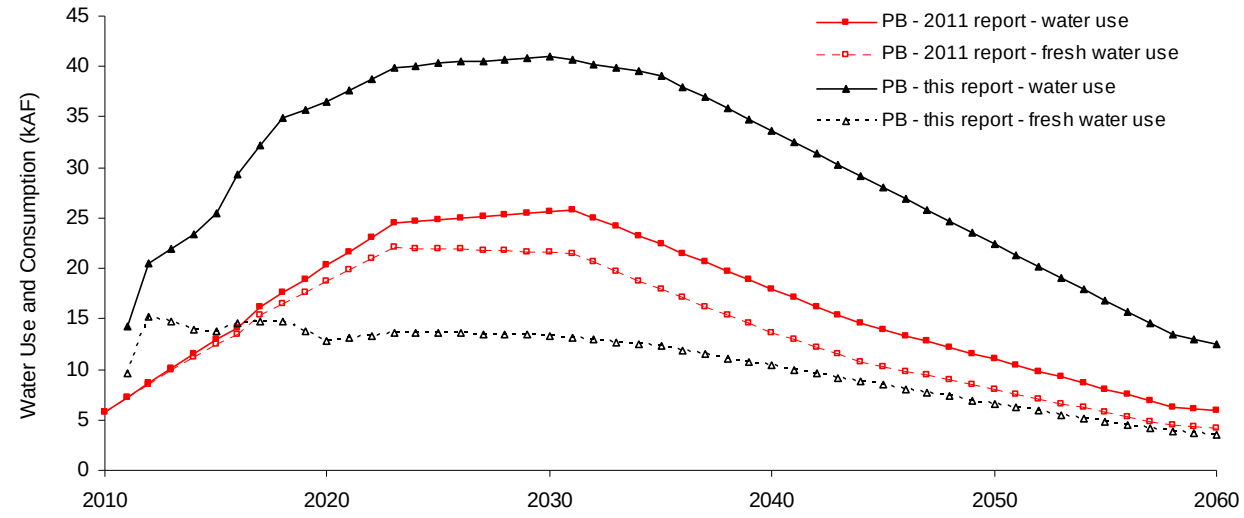


(a)

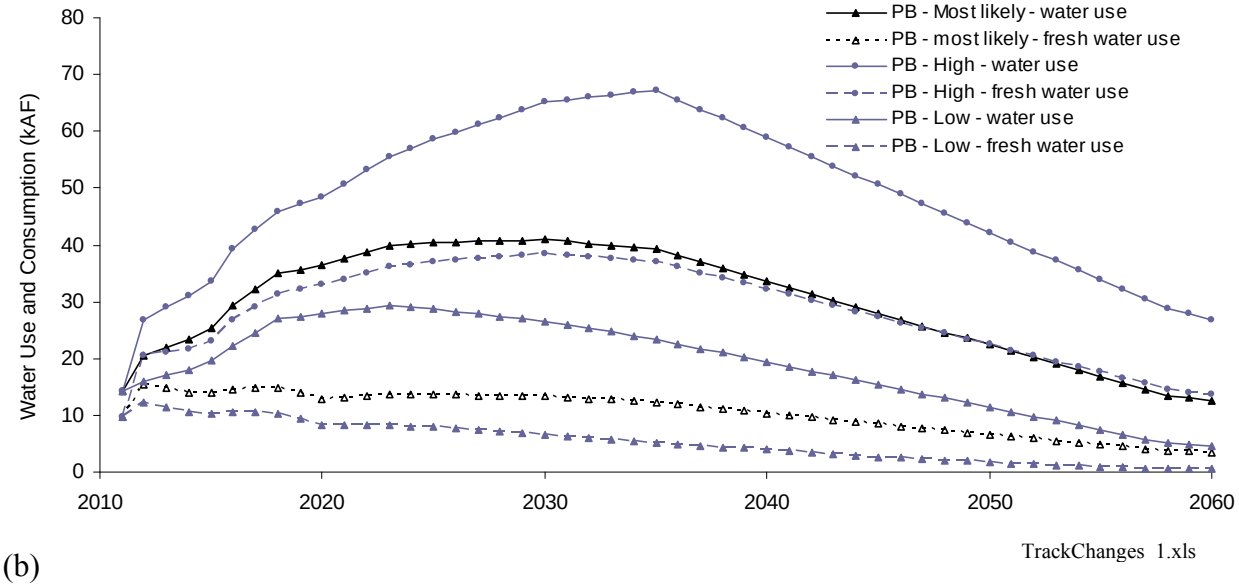


(b)

Figure 59. Anadarko Basin water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



(a)



(b)

Figure 60. Permian Basin water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

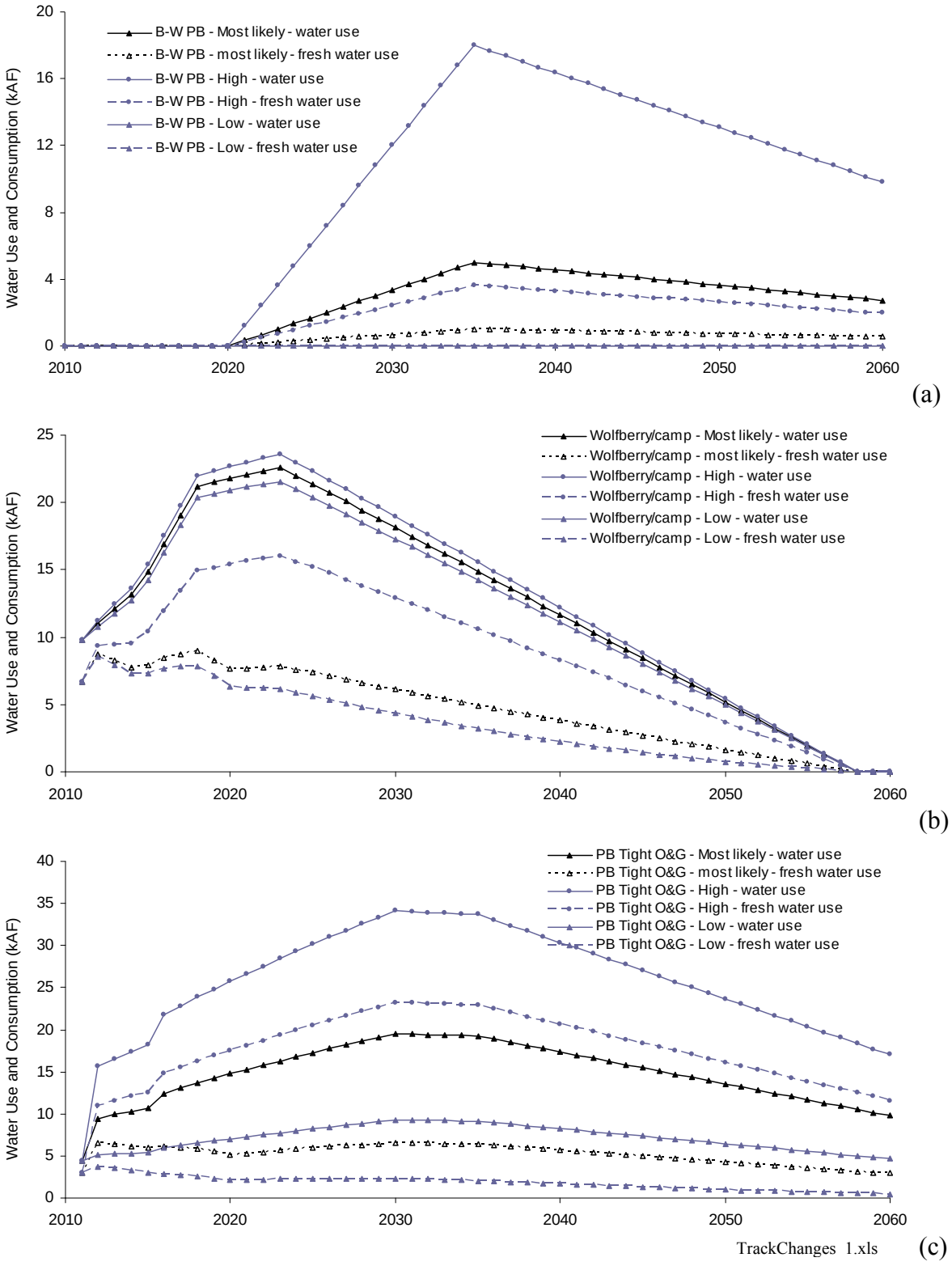
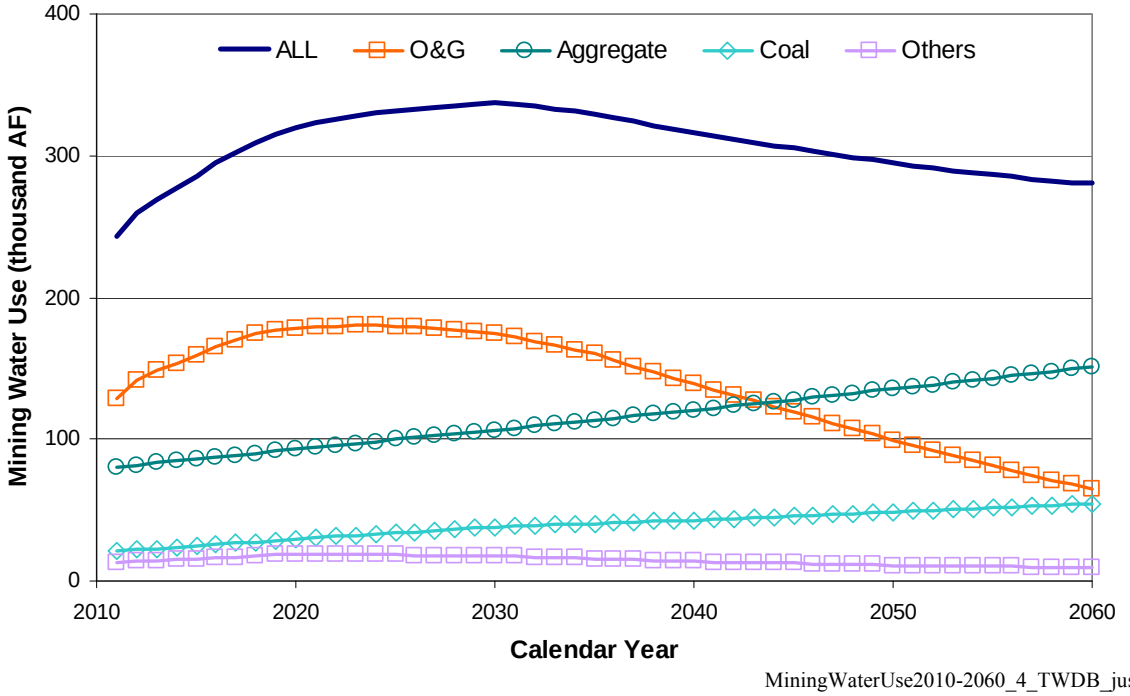


Figure 61. Permian Basin water use and consumption projections under the three scenarios: (a) Barnett and Woodford Shales; (b) Wolfcamp Shale and Wolfberry play; and (c) other Permian Basin formations.

V. Conclusions

This update to the 2011 report (whose conclusions were partly summarized in Nicot and Scanlon, 2012) does not fundamentally change the water use projections put forward originally. Both documents outline a water use that is likely to stay in the vicinity of 100±50 kAF/yr for many years. The new projections lower and broaden the expected peak water use and displace the center of gravity of HF water use toward West Texas, an area of the state that has less fresh water. This mechanically translates into a higher brackish water use which when allied with improvement in reuse technologies results in a much lower fresh water consumption than was projected in the 2011 report. The eventual solution in West Texas, after the initial step of using slightly brackish groundwater, is to use more saline brackish water or the abundant produced water from conventional wells to avoid competition with other users who will also rely more and more on brackish water as their water needs increase. In addition to this expected recycling from other uses, the industry itself is making rapidly maturing technological advances that will improve reuse. Fortunately flow back is abundant in most places where fresh water is not (such as in West Texas). However, as in all predictive work, unexpected events can generate large deviations from the projections (as the shale gas revolution did for domestic oil production). The simple discovery of an additional major play (deeper play?) beyond those described in this document could change the state-level water projections. They, however, are unlikely to deviate much in order of magnitude from those outlined here.

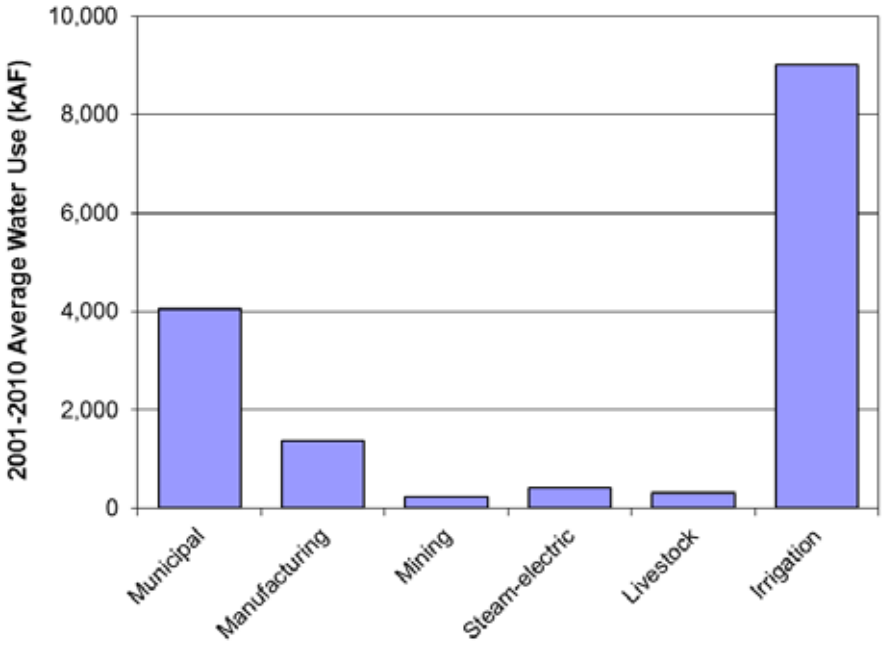
It follows that oil and gas water use projections remain a reasonable fraction of mining water use projections, no more than 54% (Figure 62) and a smaller fraction still of the total amount on water use in Texas every year: <0.1 million AF (81.5 kAF in 2011) compared to 15+ million AF (Figure 63).



MiningWaterUse2010-2060_4_TWDB_just.xls

Note: modified from the 2011 report (Nicot et al., 2011, Fig. 135)

Figure 62. Summary of projected water use by mining industry in Texas (2012-2060).



BarPlots_WaterUse_6.xls

Source: TWDB historical water use surveys, http://www.twdb.state.tx.us/waterplanning/waterusesurvey/estimates/

Note: value displayed for mining water use is the 230 kAF from Nicot et al. (2011) rather than the projected 296 kAF listed in TWDB (2012, p.137) or the 2001-2010 average of 184.4 kAF computed with limited information.

Figure 63. Average state level water use (all categories) in 2001-2010.

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Appendix 1: Revision to 2011 Report

Although the material below is now obsolete (Table 17), we thought it was important to correct Table 52 of the 2011 report ("Projected water use in the Barnett Shale (Fort Worth Basin)"). Although correct values were used in tables of higher order (state level or cumulative across water uses) in the 2011 report, its table 52 was not updated between the draft version and the final version.

Table 17. Update to Table 52 of 2011 report (now obsolete and superseded by this report)

County	2010*	2020	2030	2040	2050	2060
	AF					
Archer	0	1,618	1,292	369	0	0
Bosque	913	2,547	1,065	0	0	0
Clay	~~634~~ 951	~~3,731~~ 5,596	~~1,663~~ 2,495	0	0	0
Comanche	429	2,524	1,125	0	0	0
Cooke	101	282	118	0	0	0
Coryell	0	1,793	1,140	263	0	0
Dallas	620	769	271	0	0	0
Denton	1,674	587	0	0	0	0
Eastland	0	1,127	1,157	386	0	0
Ellis	325	235	63	0	0	0
Erath	2,017	2,500	882	0	0	0
Hamilton	190	1,118	498	0	0	0
Hill	1,008	1,249	441	0	0	0
Hood	1,720	990	215	0	0	0
Jack	~~1,835~~ 2,386	~~1,706~~ 2,218	~~535~~ 696	0	0	0
Johnson	3,308	1,537	241	0	0	0
McLennan	0	1,380	680	62	0	0
Montague	~~539~~ 809	~~3,174~~ 4.760	~~1,415~~ 2,122	0	0	0
Palo Pinto	446	2,627	1,171	0	0	0
Parker	4,003	1,787	153	0	0	0
Shackelford	0	1,121	1,151	384	0	0
Somervell	771	443	96	0	0	0
Stephens	0	1,854	1,178	272	0	0
Tarrant	3,147	1,104	0	0	0	0
Wise	~~4,220~~ 4.642	~~1,961~~ 2,157	~~308~~ 338	0	0	0
Young	0	563	578	193	0	0
Total (Th. AF)	**~~27.9~~ 29.5**	**~~40.3~~ 44.5**	**~~17.4~~ 19.2**	**1.9**	**0.0**	**0.0**

Note: double strikethrough on the incorrect values replaced by the correct but obsolete values.

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Hydraulic Fracturing: Will There Be Impacts?

What Hatchery Fish Don't Remember

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Fish? Why Fish?

New AFS Policy Statement!

AFS's Role In Education

03632415(2013)38(1)

Pushing the Limits: Using VIE to Identify Small Fish

Most tags just don't fit in small-bodied and early life stages of fish, but we still need to identify them, preferably without biasing our data. The options are further limited when many batches or individual identification is required. Visible Implant Elastomer™ (VIE) is internally injected but remains externally visible, and because the size of a tag is controlled by the tagger, it is easily adapted to very small fish. Colors and tag locations can be combined to create a coding scheme.

VIE has been used to tag newly settled coral reef fishes as small as 8—10 mm [1,2] with high tag visibility and little mortality. Marking success was influenced by depth of subcutaneous tag injection, anatomical location of the tag, pigmentation of the skin, and investigator's experience with the technique. Long-bodied fish like eels and lamprey as small as 1 g are easily tagged with VIE [3, 4].

Techniques for tagging very small salmonids have been developed for VIE. Brown trout ≤26 mm can be tagged at the base of the fins and have been recovered during stream surveys up to 83 days later[5]. This technique worked well with Atlantic Salmon ≤30 mm, and has been used for monitoring in-stream movements through snorkel surveys[6]. The minimum size for tagging juvenile salmonids has been pushed down to 22 mm FL, and is possible to tag alevins in the yolk sac[7], and fry in the fins[8].

VIE is well-suited for tagging juveniles of many other species and is used world wide. Please contact us if we can help with your project.



Photos: A syringe is used to inject VIE into the fin of a juvenile salmonid (top). VIE is available in 10 colors (left), of which six fluoresce under a VI Light for improved visibility and tag detection (center). Tagging rainbow trout fry as small as 22 mm is possible with VIE (below). Leblanc & Noakes[7] used this to identify fish originating from larger eggs (top) or smaller eggs (bottom).

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Photo courtesy C. Leblanc.

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Fisheries

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Photo Credits: foreground: Miles Luo; background: Alessandro Farsi



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Teach Your Children Well

John Boreman, President



AFS President Boreman may be contacted at: John.Boreman@ncsu.edu

This is an exciting time to be a member of the American Fisheries Society (AFS). Conservation laws, technology, and the questions being asked of fisheries professionals are changing rapidly, as well the nature of the fisheries discipline itself. In the past 20 years we have witnessed increased accountability requirements for those managing our fisheries resources, not only in the United States but also globally, putting more responsibility on the shoulders of fisheries professionals. We have seen the Internet and associated social media become a mainstay in communications among fisheries professionals and for keeping us in touch with decision makers and the public in general. We have seen computational power and associated data storage requirements increase by orders of magnitude, along with the development and use of sensors to measure the environment and its biota. Today's students (and many of today's faculty) were not yet born when our astronauts walked on the moon, when we used transistors in our radios, and spun 45s on our record players. I was shocked when none of the students in my class ever heard of FORTRAN. What's in store for fisheries professionals the next 20 years? Will we be able to adapt to changes in everything affecting our lives and livelihoods? Will we be adequately prepared to do so?

As a professional society, the AFS has a role to play in ensuring that people entering the future workforce will be prepared to tackle the issues that fisheries professionals will then be facing. This role is codified in the AFS Strategic Plan for 2010–2014:

> *Guide colleges and universities to maintain, modify, or develop curricula of the highest quality for both undergraduate and graduate students that provide an array of courses and experiences needed to effectively manage and conserve fisheries resources and meet the needs of employers.*

In keeping with my theme "Preparing for the Challenges Ahead," I have established an AFS Special Committee on Educational Requirements, chaired by AFS Second Vice President Ron Essig, to accomplish several tasks. First, the committee will assemble a list of North American colleges and universities currently offering undergraduate and graduate degrees in fisheries-related disciplines (e.g., fisheries science, fisheries biology, fisheries ecology, fisheries management, fisheries policy, and fisheries economics) and publish the list on the AFS website. Concurrently, the committee will oversee a survey of major employers that will be hiring graduates with degrees in fisheries-related disciplines in the next 5–10 years to determine what coursework those graduates will be expected to have taken that would be most germane to the positions being filled. The survey results, and an evaluation of their implications, should be published in *Fisheries*. When the list and survey are completed, the committee will compare the coursework expectations of the employers with the current coursework requirements of a selected subset of colleges and universities offering fisheries degrees. If the comparison indicates a misalignment, the committee will recommend ways in which an alignment can be made, which could range from giving simple advice to the colleges and universities to instituting an accreditation program administered by the AFS (or something in between). The recommendations could serve as the basis for discussion at an upcoming AFS Governing Board retreat.

I have also asked the special committee to compare coursework expectations resulting from the survey to degree requirements for certification as a fisheries professional, working with the Education Subcommittee of the AFS Board of Professional Certification, as well as to the U.S. Office of Personnel Management's educational requirements in the grade-level qualification standards for the 482 (Fish Biology) series. Based on the comparisons, the committee could recommend changes that would bring the degree requirements for certification and federal employment into alignment with employer expectations. The committee might also look at analogous requirements for federal employment of fisheries professionals in Mexico and Canada. These comparisons can be published as a series of articles in *Fisheries*.

Continuing education, which helps fisheries professionals shore up their level of skill, knowledge, and expertise as employment demands evolve, is also important in preparing the future workforce. To this end, I have charged the AFS Continuing Education Committee to assist AFS staff in expanding opportunities for distance education (i.e., education via the Internet) beyond virtual attendance at continuing education courses offered at the annual meeting. One option the Continuing Education Committee will be tackling through the AFS will be to pilot at least one half-day short course in the coming year to be offered via a webinar. The pilot short course could be offered for free to alleviate complications with registration and fees and allow the committee to focus evaluation of the pilot solely on the quality of the learning experience. Given successful delivery of the pilot course, the AFS could pursue, for example, a quarterly distance education webinar series that may or may not require

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Hydraulic Fracturing and Brook Trout Habitat in the Marcellus Shale Region: Potential Impacts and Research Needs

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ABSTRACT: *Expansion of natural gas drilling into the Marcellus Shale formation is an emerging threat to the conservation and restoration of native brook trout (*Salvelinus fontinalis*) populations. Improved drilling and extraction technologies (horizontal drilling and hydraulic fracturing) have led to rapid and extensive natural gas development in areas overlying the Marcellus Shale. The expansion of hydraulic fracturing poses multiple threats to surface waters, which can be tied to key ecological attributes that limit brook trout populations. Here, we expand current conceptual models to identify three potential pathways of risk between surface water threats associated with increased natural gas development and life history attributes of brook trout: hydrological, physical, and chemical. Our goal is to highlight research needs for fisheries scientists and work in conjunction with resource managers to influence the development of strategies that will preserve brook trout habitat and address Marcellus Shale gas development threats to eastern North America's only native stream salmonid.*

Ruptura hidráulica y el hábitat de la trucha de arrollo en la región de Marcellus Shale: impactos potenciales y necesidades de investigación

RESUMEN: El crecimiento de las actividades de perforación de gas natural en la formación Marcellus Shale es una amenaza emergente para la conservación y restauración de las poblaciones nativas de la trucha de arroyo (*Salvelinus fontinalis*). La perforación más eficiente y las tecnologías de extracción (perforación horizontal y ruptura hidráulica) han facilitado el rápido y extensivo desarrollo de esta industria a las áreas que comprende la región Marcellus Shale. La expansión de las rupturas hidráulicas representa múltiples amenazas a las aguas superficiales, que pueden estar asociadas a atributos ecológicos clave que limitan las poblaciones de la trucha de arroyo. En la presente contribución se expanden los modelos conceptuales actuales que sirven para identificar tres fuentes potenciales de riesgo entre las amenazas a las aguas superficiales asociadas al creciente desarrollo del gas natural y los atributos de la historia de vida de la trucha de arroyo; atributos hidrológicos, físicos y químicos. El objetivo de este trabajo es hacer notar las necesidades de investigación para los científicos pesqueros y trabajar junto con los manejadores de recursos para influir en el desarrollo de estrategias tendientes a preservar el hábitat de la trucha de arroyo; así mismo se atienden las amenazas que representa el desarrollo de la industria del gas natural para el único salmónido nativo de América del norte.

INTRODUCTION

Hydraulic Fracturing in the Marcellus Shale

Natural gas extraction from subterranean gas-rich shale deposits has been underway in the northeastern United States for almost 200 years but has expanded rapidly over the past decade within the Devonian Marcellus Shale formation (P. Williams 2008). This expansion has largely been driven by the development and refinement of the horizontal hydraulic fracturing process (United States Energy Information Administration 2011a). Horizontal gas drilling differs from the more traditional vertical drilling process because the well is drilled to the depth of the shale stratum and then redirected laterally, allowing for access to a larger area of subterranean shale (Figure 1). Drilling is followed by the hydraulic fracturing process, which involves injecting a chemically treated water-based fluid into the rock formation at high pressure to cause fissures in the shale and permit the retrieval of gas held within the pore space of the shale. The fissures are kept open by sand and other proppants, which allow gas to be extracted (Soeder and Kappel 2009; Kargbo et al. 2010). The hydraulic fracturing process was granted exemptions to the Clean Water and the Safe Drinking Water Acts under the Energy Policy Act of 2005. Drilling has since expanded rapidly in the Marcellus Shale deposit in portions of West Virginia and Pennsylvania (Figure 2), is expected to continue into Ohio and New York, and will likely continue to expand within these states to include the gas-bearing Utica Shale formation.

Brook Trout Status within the Marcellus Shale

Eastern brook trout are native to the Eastern United States, with a historic range extending from the southern Appalachians in Georgia north to Maine (MacCrimmon and Campbell 1969; Figure 2). Brook trout require clean, cold water (optimal tem-

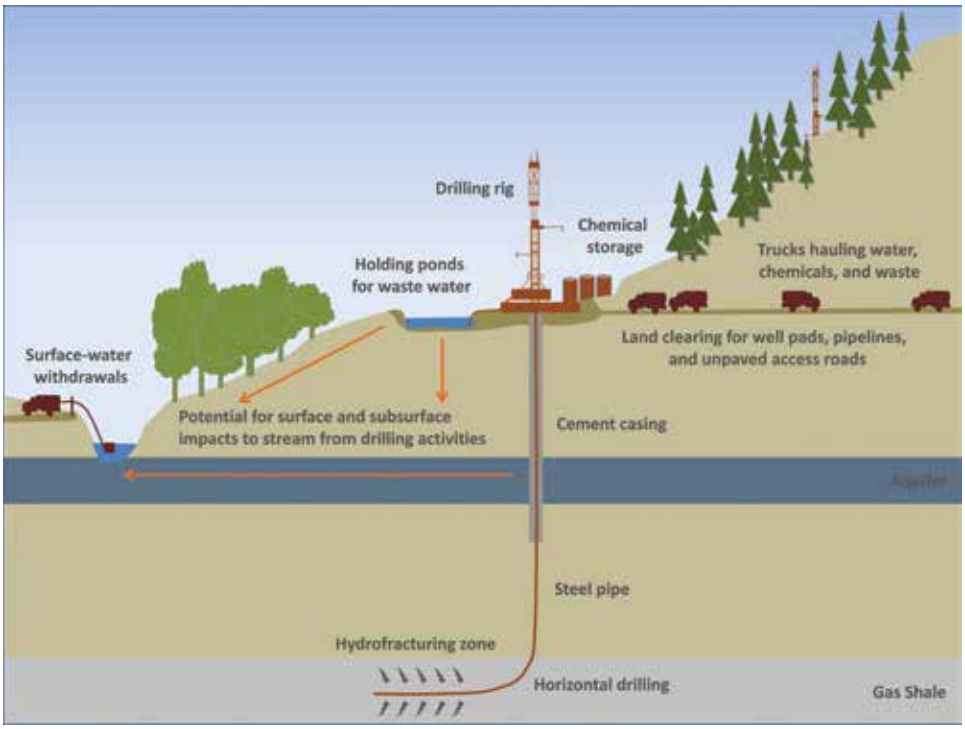


Figure 1. Conceptual diagram depicting the hydraulic fracturing process. A rig drills down into the gas-bearing rock and the well is lined with steel pipe. The well is sealed with cement to a depth of 1,000 ft. to prevent groundwater contamination. The well is extended horizontally 1,000 ft. or more into the gas-bearing shale where holes are blasted through the steel casing and into the surrounding rock. Sand, water, and chemicals are pumped into the shale to further fracture the rock and gas escapes through fissures propped open by sand particles and back through the well up to the surface. Supporting activities include land clearing for well pads and supporting infrastructure, including pipelines and access roads. Trucks use roads to haul in water extracted from local surface waters, chemicals, and sand. Recovered water is stored in shallow holding ponds until it can be transported by truck to treatment facilities or recycled to fracture another well. These activities may impact nearby streams through surface and subsurface pathways.

perature = 10–19°C), intact habitat, and supporting food webs to maintain healthy populations, making them excellent indictors of anthropogenic disturbance (Hokanson et al. 1973; Lyons et al. 1996; Marschall and Crowder 1996). Only 31% of subwatersheds (sixth level, 12-digit hydrological units [HUC12], as defined by the Watershed Boundary Dataset; U.S. Department of Agriculture, Natural Resources Conservation Service 2012) within the historic range of brook trout are currently expected to support intact populations (self-sustaining populations greater than 50% of the historical population; Hudy et al. 2008). Substantial loss of brook trout populations within their native range is due to anthropogenic impacts that have resulted in habitat fragmentation and reduction, water quality and temperature changes, and alteration of the biological environment through introduction and removal of interacting species (Hudy et al. 2008). Conservation efforts, including formation of the Eastern Brook Trout Venture (Eastern Brook Trout Joint Venture [EBTJV] 2007, 2011) and a shift by organizations such as Trout Unlimited (TU) to policies that oppose the stocking of nonnative hatchery-produced salmonids in native trout streams (TU 2011), are focused on maintaining and restoring brook trout populations in their native range. With these growing concerns about the future of native brook trout populations, natural gas well development within the Marcellus Shale region presents another potential threat to native brook trout populations.

Twenty-six percent of the historic distribution of brook trout habitat overlaps with the Marcellus Shale (Figure 2). The Pennsylvania portion of the Marcellus Shale has experienced the largest increase in natural gas development (Figure 2). Between January 1, 2005, and May 31, 2012, the cumulative number of Marcellus Shale well permits issued in Pennsylvania increased from 17 to 11,784 (Pennsylvania Department of Environmental Protection [PADEP] 2012a). Of these permitted wells, 5,514 were drilled during the same time period (PADEP 2012b; Figure 3A). Trends in drilled well densities among subwatersheds during the rapid expansion of drilling activity suggest that there have not been any extra protections granted during the well permitting process for subwatersheds that are expected to support intact brook trout populations (Figure 3B). Fifty-four of the 134 subwatersheds categorized as having intact brook trout populations within the Marcellus Shale region have already experienced drilling activity (Hudy et al. 2008). Overall, Marcellus drilling activity has expanded to 377 subwatersheds (mean area = 94.8 ± 1.9 km^2) in Pennsylvania (Figure 4).Within these 377 subwatersheds, patterns in well density over time show similar trends among subwatersheds varying in their current brook trout population status (Figure 3B). Though there is a significant difference in current well densities among the three subwatershed types (one-way analysis of variance [Type II], $F_{2, 292} = 4.14$, $P = 0.02$), mean well density does not differ between subwatersheds where brook trout are extirpated/unknown and those with intact brook trout populations (Tukey's multiple comparison test, $\alpha = 0.05$; Figure 3B). In fact, the two highest drilling densities include an extirpated/unknown subwatershed (16.7 wells/10 km^2) and a subwatershed expected to support intact brook trout populations (15.1 wells/10 km^2; Figure 4). These trends highlight that increasing hydraulic fracturing development is occurring not only in degraded subwatersheds but also in those that support an already vulnerable native species and valuable sport fish. This trend should be of concern to fisheries scientists, managers, and conservationists who work to maintain and improve the current status of this natural heritage species.

Linking Marcellus Shale Drilling Impacts to Brook Trout Population Health

Recent efforts to conceptualize horizontal hydraulic fracturing impacts have focused on stream ecosystems and regional

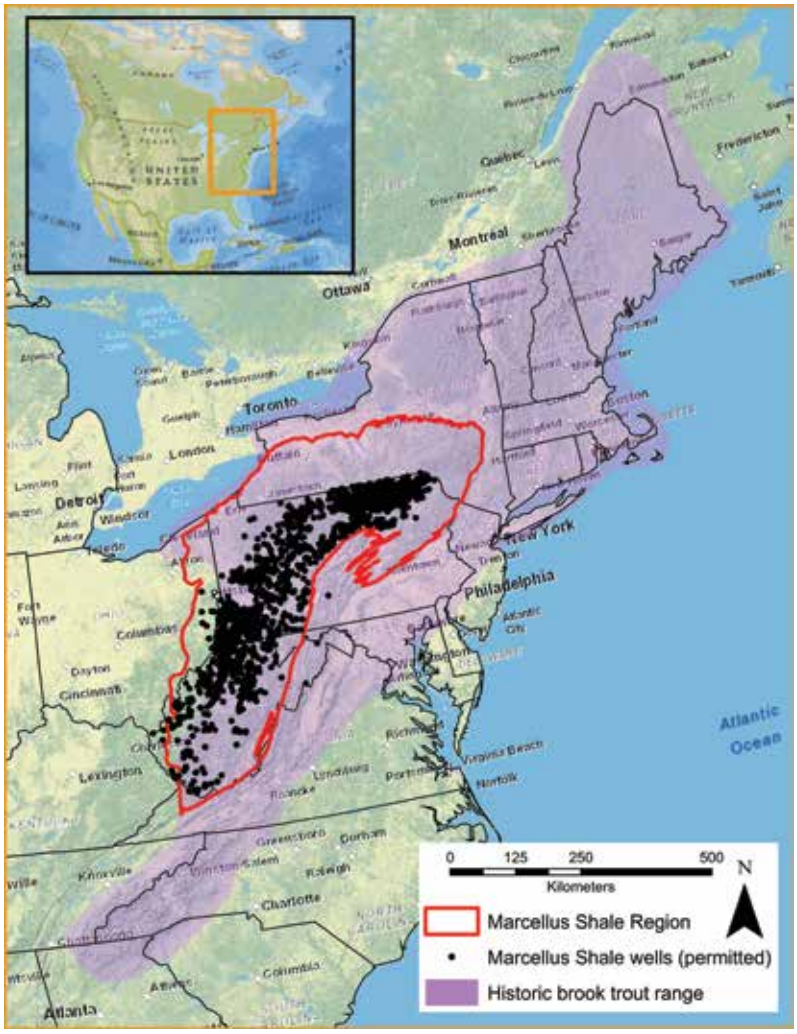


Figure 2. Overlay of the Marcellus Shale region of the Eastern United States (U.S. Geological Survey [USGS] 2011) and the historic distribution of eastern brook trout (Hudy et al. 2008) with permitted Marcellus Shale well locations, 2001–2011 (Ohio Department of Natural Resources 2011; West Virginia Geological and Economic Survey 2011; PADEP 2012a).

water supplies but not on potential pathways to particular target organisms. Herein, we integrate two existing conceptual models of potential natural gas development impacts to surface waters and link them to different brook trout life history attributes (Entrekin et al. 2011; Rahm and Riha 2012). Entrekin et al.'s (2011) conceptual model establishes connections between hydraulic fracturing activities and the ecological endpoint of stream ecosystem structure and function by way of potential environmental stressors from drilling activity sources. These stressors to stream ecosystems can be planned activities that must necessarily occur in the hydraulic fracturing process (deterministic events) or those that may occur unexpectedly (probabilistic events; Rahm and Riha 2012). Brook trout have different environmental requirements at the various stages of their life cycle and may be sensitive to potential impacts associated with the current expansion of hydraulic fracturing; thus, understanding the environmental stressors associated with hydraulic fracturing has implications for fisheries conservation, including maintenance and/or enhancement of native brook trout populations.

We delineated relationships between various stream ecosystem attributes that are potentially impacted by increased drilling activities and different aspects of the brook trout life cycle (Figure 5). A review of extant literature on the activities associated with natural gas drilling and other extractive industries and of the environmental changes known to directly influence brook trout at one or more of their life stages identified three primary pathways by which increased drilling will likely impact brook trout populations. The primary pathways include (1) changes in hydrology associated with water withdrawals; (2) elevated sediment inputs and loss of connectivity associated with supporting infrastructure; and (3) water contamination from introduced chemicals or wastewater (Entrekin et al. 2011; Rahm and Riha 2012). These three pathways may be considered natural gas drilling threats to brook trout populations that require study and monitoring to fully understand, minimize, and abate potential impacts.

PATHWAY #1: WITHDRAWALS → HYDROLOGY → BROOK TROUT

Two to seven million gallons of water are needed per hydraulic fracturing stimulation event; a single natural gas well can be fractured several times over its lifespan, and a well pad site can host multiple wells (Soeder and Kappel 2009; Kargbo et al. 2010). This large volume of water needed per well, multiplied by the distributed nature of development across the region, suggests that hydraulic fracturing techniques for natural gas development can put substantial strain on regional water supplies. This level of water consumption has sparked concern among hydrologists and aquatic biologists about the sourcing of the water, as well as the implications for available habitat and other hydrologically influenced processes in adjacent freshwater ecosystems (Entrekin et al. 2011; Gregory et al. 2011; Baccante 2012; Rahm and Riha 2012; Figure 5). Surface water is the primary source for hydraulic fracturing–related water withdrawals in at least one major basin intersecting the Marcellus Shale region (Susquehanna River Basin Commission [SRBC] 2010), but groundwater has been a major water source in other natural gas deposits such as the Barnett Shale region in Texas (Soeder and Kappel 2009). The cumulative effects of multiple surface and/or groundwater withdrawals throughout a watershed have the potential to effect downstream hydrology and connectivity of brook trout habitats (Rahm and Riha 2012; Petty et al. 2012).

Aquatic habitat is particularly limited by low-flow periods during the summer for fish and other aquatic organisms (Figure 6). Changes in temperature and habitat volume during summer low-flow periods are primary factors limiting brook trout populations (Barton et al. 1985; Wehrly et al. 2007; Xu et al. 2010). Brook trout rely on localized groundwater discharge areas within pools and tributary confluences to lower body temperature below that of the ambient stream temperature during

warm periods, and groundwater withdrawals can alter these temperature refugia. Additionally, access to thermal refugia may be limited by loss of connectivity associated with reduced flows between temperature refugia (headwater streams, seeps, tributary confluences, groundwater upwellings) and larger stream habitats (Petty et al. 2012). Reduced flows, particularly coldwater inputs, may inhibit growth rates by reducing feeding activity of both juveniles and adults or inducing sublethal heat shock at temperatures above 23°C and lethal effects at 24–25°C (7-day upper lethal temperature limit; Cherry et al. 1977; Tangiguchi et al. 1998; Baird and Krueger 2003; Lund et al. 2003; Wehrly et al. 2007). Recovery from thermal stress responses (heat shock) can be prolonged (24–48 h) even if exposure to high stream temperatures is relatively short (1 h) but may be more than 144 h when exposed to high temperatures for multiple days (Lund et al. 2003). Adult abundance and biomass of brook trout in run habitats declines with flow reduction and carrying capacity is likely limited by available pool area during low-flow periods (Kraft 1972; Hakala and Hartman 2004; Walters and Post 2008).

Reduction in surface water discharge during summer months may also indirectly impact brook trout growth by decreasing macroinvertebrate prey densities (Walters and Post 2011) in small streams and lowering macroinvertebrate drift encounter rates for drift-feeding salmonids (Cada et al. 1987; Nislow et al. 2004; Sotiropoulos et al. 2006; Figure 5). Other indirect effects may include increasing interspecific competition through habitat crowding, especially with more tolerant competitor species such as brown trout (*Salmo trutta*) and rainbow trout (*Oncorhynchus mykiss*), due to decreased habitat availability and increased temperature during low-flow periods. Introduced brown trout tend to out-compete brook trout for resources and have higher growth rates in all but the smallest, coldest headwater streams (Carlson et al. 2007; Öhlund et al. 2008; Figure 5). Additionally, salmonids may be more susceptible to disease or infestation of parasites when the temperature of their environment is not consistent and adequately cool (Cairns et al. 2005), a problem that could be exacerbated by the crowding in pool habitats that can occur as a result of flow reductions (Figure 5). Sediment accrual in redds can limit recruitment (Alexander and Hansen 1986; Argent and Flebbe 1999), and adequate summer base flows coupled with occasional high flow pulses are important for preparing sediment free spawning redds (Hakala and Hartman 2004). DePhilip and Moberg (2010) demonstrated that the magnitude of withdrawals proposed by drilling companies in the Susquehanna River basin has the potential to impact summer and fall low flows, and in some cases, high-flow events (Q_{10}) in small streams.

Water withdrawals may also impact brook trout spawning activities and recruitment during higher flow periods (Figures 5 and 6). Brook trout peak spawning activity typically occurs at the beginning of November in gravel substrates immediately downstream from springs or in places where groundwater seepage enters through the gravel (Hazzard 1932). Withdrawals during the fall may dewater and reduce available spawning habitat, particularly during low-flow years. Additionally, stable base

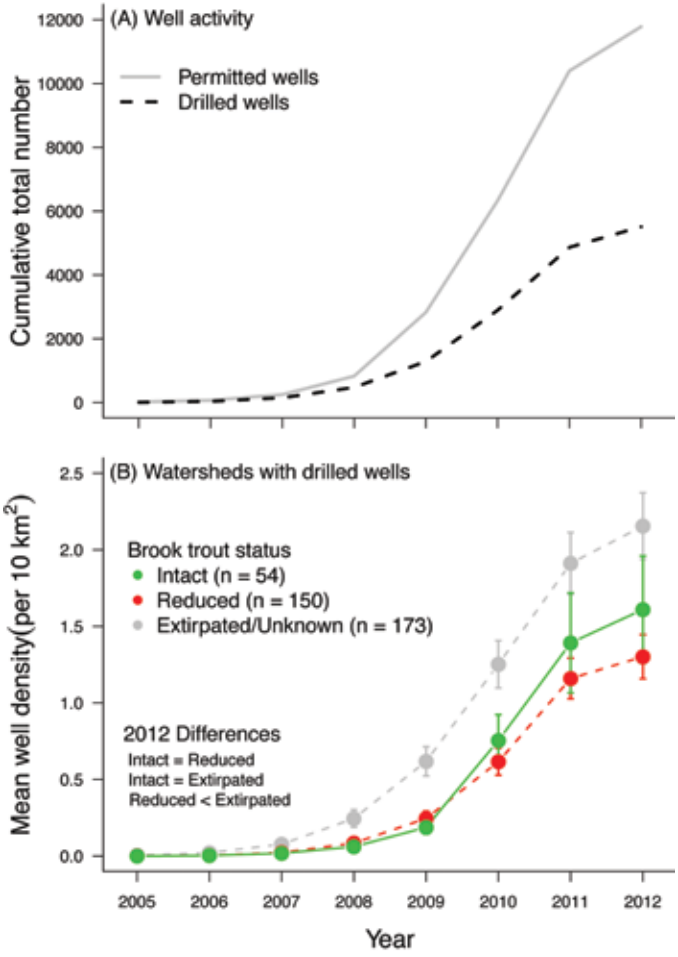


Figure 3. Well permitting and drilling in the Pennsylvania portion of Marcellus Shale from January 1, 2005, through May 31, 2012. (A) Cumulative number of permitted and drilled wells over time. (B) Mean well density (wells per 10 km^2) over time for 377 actively drilled HUC12 subwatersheds, grouped by status of brook trout population (Hudy et al. 2008). Permitted and drilled Marcellus well data are from PADEP (2012a, 2012b), respectively.

flows after spawning are necessary for maintaining redds during egg incubation throughout winter (Figure 6). Maintaining base flow in trout spawning habitats throughout the incubation period maintains shallow groundwater pathways, chemistry, and flow potentials in redds (Curry et al. 1994, 1995), which protect developing eggs from sedimentation (Waters 1995; Curry and MacNeill 2004) and freezing (Curry et al. 1995; J. S. Baxter and McPhail 1999). Thus, insuring that water withdrawals required for hydraulic fracturing do not interrupt stable winter base flows in small coldwater streams is an important consideration in protecting brook trout recruitment in the Marcellus Shale region (Figures 5 and 6).

PATHWAY #2: INFRASTRUCTURE → PHYSICAL HABITAT → BROOK TROUT

Natural gas extraction requires development of well pad sites and infrastructure for transportation and gas conveyance, which involves a set of activities that will likely have impacts on water quality and habitat quality for brook trout unless proper precautions and planning are implemented. These activities

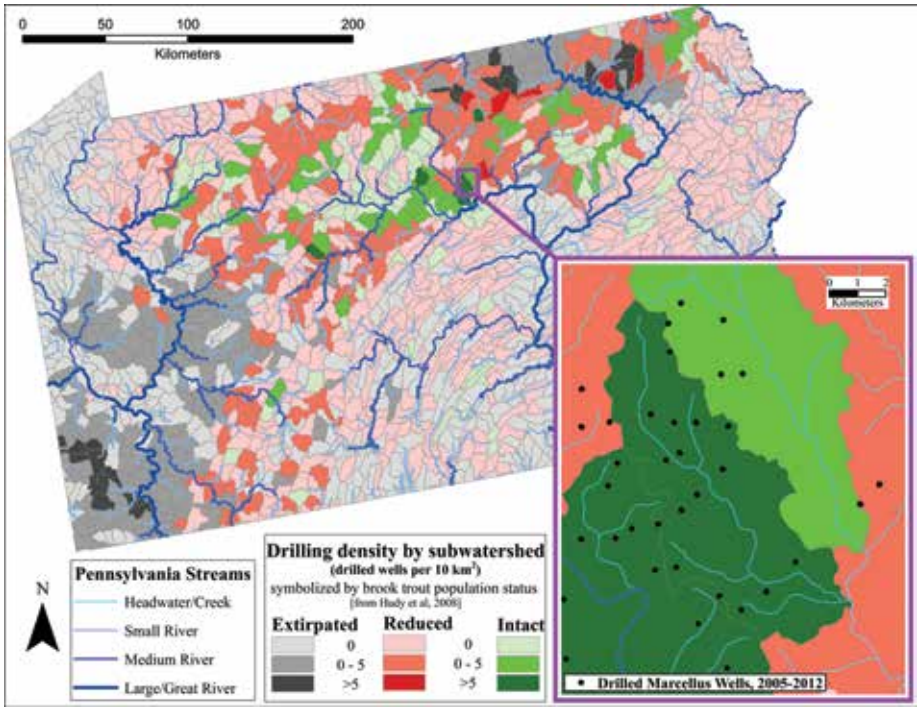


Figure 4. Density of wells drilled in the Pennsylvania portion of the Marcellus Shale by HUC12 subwatershed (well drilling locations from PADEP 2012b; 12-digit HUC subwatershed boundaries and areas from USGS Watershed Boundary Dataset; U.S. Department of Agriculture, Natural Resources Conservation Service 2012), symbolized by status of current brook trout population (Hudy et al. 2008). Inset: A subwatershed expected to support an intact brook trout population that currently has the second highest well density (15.1 wells/10 km2) of all drilled subwatersheds.

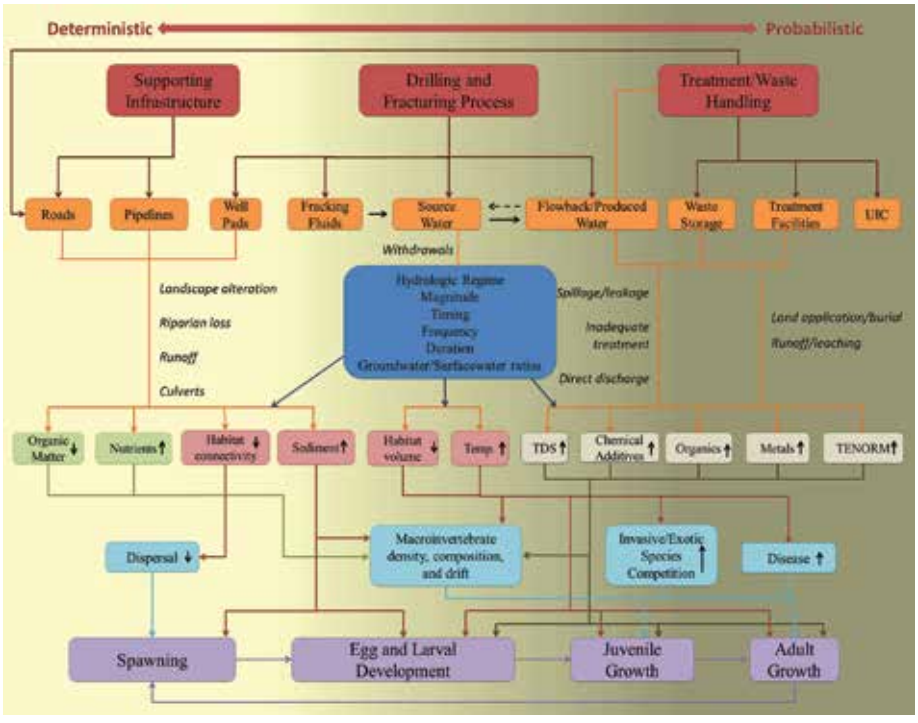


Figure 5. Conceptual model of relationships between hydraulic fracturing drilling activities and the life cycle of eastern brook trout (modified from conceptual models based on Entrekin et al. [2011] and Rahm and Riha [2012]).

include, but are not limited to, construction of well pads, roadways, stream crossings, and pipelines; increased use of existing rural roadways for transportation of equipment, source water, recycled flow-back, and wastes associated with hydraulic fracturing activities; and storage of these same materials (Figure 1). Increased sediment loads and loss of stream connectivity are some of the stream impacts associated with these deterministic activities, which could reduce habitat quality and quantity needed for brook trout spawning success, egg development, larval emergence, and juvenile and adult growth and survival (Figure 5).

Brook trout are particularly sensitive to the size and amount of sediment in streams, with coarse gravel providing a more suitable substrate than fine particles (Witzel and MacCrimmon 1983; Marschall and Crowder 1996). Well pad site, access road, and pipeline corridor construction require land clearing, which can mobilize from tens to hundreds of metric tons of soil per hectare (H. Williams et al. 2008; Adams et al. 2011). Pipeline construction (Reid et al. 2004) and unpaved rural roadways (Witmer et al. 2009) crossing streams can trigger additional sediment inputs to streams. Road and well pad densities have been found to be positively correlated with fine sediment accumulation in streams (Opperman et al. 2005; Entrekin et al. 2011), which disrupts fish reproduction and can lead to mortality (Taylor et al. 2006). Overall, trout populations have been found to decline in abundance, even with small increases in stream sediment loads (Alexander and Hansen 1983, 1986). Sediment can impact all stages of trout life cycles, because turbidity reduces foraging success for adults and juveniles (Sweka and Hartman 2001), and sediment accumulation can cause oxygen deprivation in salmonid redds and reduce successful emergence of larvae from eggs (Witzel and MacCrimmon 1983; Waters 1995; Argent and Flebbe 1999; Curry and MacNeill 2004; Figure 5).

The spatial and temporal extent of sediment impacts to streams is linked to the scale and persistence of mobilizing activities. For example, localized events, such as construction of culverts

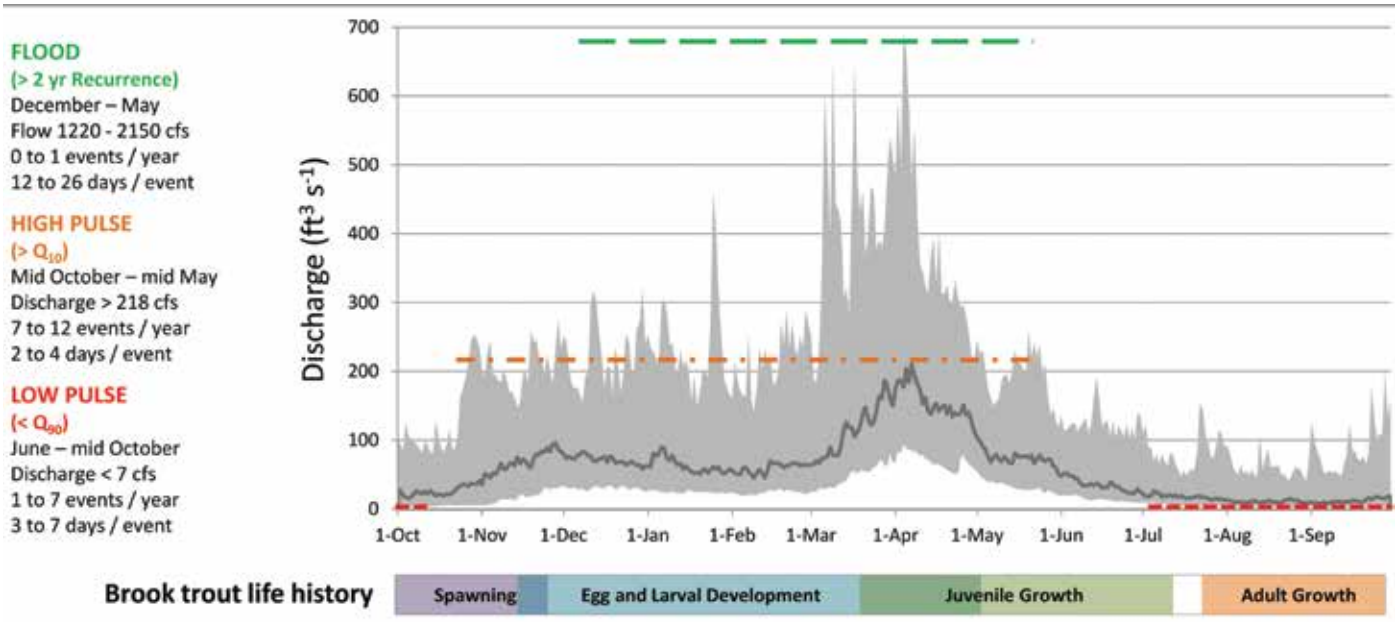


Figure 6. Hydrologic patterns for a trout supporting stream with relatively unaltered hydrology (Little Delaware River, USGS Gage 01422500, watershed area = 129 km2) in relation to timing of brook trout life history periods. Median (dark line), bounded by 10th and 90th percentile daily flows (grey) for 47 years of discharge data. Important flood, high-, and low-flow components were computed and described using Indicators of Hydrologic Alteration (The Nature Conservancy 2009).

at stream road crossings can increase sediment loads for up to 200 m downstream of the culvert over a 2- to 3-year period (Lachance et al. 2008). Conversely, the sediment loads associated with more diffuse land clearing activities and frequent and sustained access into rural areas by large vehicles can contribute to reductions in brook trout biomass and densities and shifts in macroinvertebrate communities that last approximately 10 years (VanDusen et al. 2005).

Sedimentation from drilling infrastructure development can further impact brook trout indirectly by reducing the availability of prey (Figure 5): high sediment levels reduce species richness and abundance of some aquatic macroinvertebrates (Waters 1995; Wohl and Carline 1996; VanDusen et al. 2005; Larsen et al. 2009), with high sediment environments generally experiencing a shift from communities rich in mayflies (Ephemoptera), stoneflies (Plectoptera), and caddisflies (Trichoptera) to those dominated by segmented worms (Oligochaeta) and burrowing midges (Diptera: Chironmidae; Waters 1995). Riparian clearing can also diminish food sources for brook trout populations, which tend to depend heavily on terrestrial macroinvertebrates (Allan 1981; Utz and Hartman 2007). However, shifts in the prey base from shredder-dominated communities that support higher brook trout abundance to grazer-dominated communities have been observed in recently logged watersheds due to higher primary productivity associated with increased sunlight from sparser canopy cover (Nislow and Lowe 2006). Consequently, land clearing and infrastructure development will likely increase sediment loads, culminating in changes in composition and productivity of the invertebrate prey base for brook trout, although not all of these changes will necessarily be negative for brook trout (Figure 5).

Conveyance of hydraulic fracturing equipment and fluids, and the extracted natural gas, into and out of well pad sites often necessitates crossing streams with trucks and pipelines. Culvert construction for roadway and pipeline stream crossings, if not properly designed, can create physical barriers that fragment brook trout habitat and disrupt their life cycle by preventing movement of adult fish into upstream tributaries for spawning and repopulation of downstream habitat by new juveniles (Wofford et al. 2005; Letcher et al. 2007; Poplar-Jeffers et al. 2009; Figure 5). Barriers to connectivity negatively impact fish species richness (Nislow et al. 2011), and habitat fragmentation without repopulation can cause local population extinction (Wofford et al. 2005; Letcher et al. 2007). Additionally, connectivity between larger stream reaches that provide food resources during growth periods and small headwater streams that may serve as temperature refugia during warmer months is important for overall population health (Utz and Hartman 2006; Petty et al. 2012). For these reasons, land clearing activities, road densities, and culvert densities can have a negative impact on trout reproductive activity and overall population size (Eaglin and Hubert 1993; C. V. Baxter et al. 1999).

PATHWAY #3: CHEMICAL WASTE → WATER QUALITY→ BROOK TROUT

Probabilistic events during the drilling process such as runoff from well pads, leaching of wastewater from holding ponds, or spills of hydraulic fracturing fluids during transportation to processing sites can affect the chemical composition of streams (Rahm and Riha 2012). Although the specific chemical composition of fracturing fluids is typically proprietary information, voluntary reporting of the content of fracturing fluids to the FracFocus Chemical Disclosure Registry (a partnership

between the Ground Water Protection Council [GWPC] and Interstate Oil and Gas Compact Commission [IOGCC], supported the U.S. Department of Energy [USDOE]) has become more common (USDOE 2011). Fracturing fluids are generally a mix of water and sand, with a range of additives that perform particular roles in the fracturing process, including friction reducers, acids, biocides, corrosion inhibitors, iron controls, cross-linkers, breakers, pH-adjusting agents, scale inhibitors, gelling agents, and surfactants (GWPC and IOGCC 2012). The wastewater resulting from the hydraulic fracturing process is high in total dissolved solids (TDS), metals, technologically enhanced naturally occurring radioactive materials (TENORM), and fracturing fluid additives (U.S. Environmental Protection Agency [USEPA] 2012). Increased metals and elevated TDS from probabilistic spill events, or deterministic events including direct discharge of treated flow-back water into streams, will likely have negative effects on stream ecosystems that support brook trout populations (Figure 5).

Elevated concentration of metals causes decreased growth, fecundity, and survival in brook trout. In particular, aluminum has been shown to cause growth retardation and persistent mortality across life stages (Cleveland et al. 1991; Gagen et al. 1993; Baldigo et al. 2007), chromium reduces successful emergence of larvae and growth of juveniles (Benoit 1976), and cadmium can diminish reproductive success by causing death of adult trout prior to successful spawning (Benoit et al. 1976; Harper et al. 2008). Trout normally exhibit avoidance behaviors to escape stream reaches that are overly contaminated with heavy metals; however, because brook trout are so heavily reliant on low-temperature environs, they seek out refugia of cold groundwater outflow even if the water quality is prohibitively low (Harper et al. 2009). Thus, if groundwater is contaminated and the groundwater-fed portions of a stream are receiving a significant contaminant load, brook trout might be recipients of high concentrations of those contaminants.

Total dissolved solids represent an integrative measure of common ions or inorganic salts (sodium, potassium, calcium, magnesium, chloride, sulfate, and bicarbonate) that are common components of effluent in freshwaters (Chapman et al. 2000). Elevated TDS and salinity may have negative effects on spawning and recruitment of salmonids by decreasing egg fertilization rates and embryo water absorption, altering osmoregulation capacity, and increasing posthatch mortality (Shen and Leatherland 1978; Li et al. 1989; Morgan et al. 1992; Stekoll et al. 2009; Brix et al. 2010). There is also evidence from western U.S. lakes with increasing TDS concentrations that growth and survival of later life stages may be negatively impacted as well (Dickerson and Vinyard 1999). Elevated salinities can lower salmonid resistance to thermal stress (Craigie 1963; Vigg and Koch 1980), which may influence competition between brook trout and more tolerant brown trout (Öhlund et al. 2008). There is a growing body of evidence supporting associations between declines in macroinvertebrate abundance, particularly mayflies, and increased TDS or surrogate specific conductivity related to mining activities within the Marcellus Shale region (Kennedy et al. 2004; Hartman et al. 2005; Pond et al. 2008; Pond 2010; Bernhardt and Palmer 2011). Overall, changes in TDS associated with improper handling or discharge of flow-back water will likely impact brook trout through direct and indirect pathways including changes in macroinvertebrate communities that serve as the prey base and/or the alteration of environmental conditions to those more favorable for harmful invasive species (i.e., Golden algae; Renner 2009; Figure 5).

A FRAMEWORK FOR ADDRESSING RESEARCH NEEDS

Our examination of potential impacts of hydraulic fracturing for natural gas extraction in the Marcellus Shale on brook trout populations reveals three key pathways of influence: hydrological, physical, and chemical. These pathways originate from the various activities associated with the hydraulic fracturing method of natural gas extraction and may affect brook trout at one or more stages of their life cycle through direct and indirect mechanisms (Figure 5). The hydrological pathway is the broadest in that it is influenced by events at both the surface and groundwater levels and, subsequently, it influences brook trout both directly through flow regimes and indirectly by also influencing physical and chemical pathways. The primary drilling activity driving the hydrological pathway is the need for source water for the hydraulic fracturing process. The physical habitat pathway originates from the infrastructural requirements of the natural gas extraction industry, which can be expected to increase stream sedimentation and impede brook trout at all life phases. The consequences of infrastructural development further impact brook trout populations if road-building activities and poorly designed road-crossing culverts reduce connectivity between spawning areas, temperature refugia, and downstream habitats. Finally, the chemical pathway addresses the potential for contamination of streams by the hydraulic fracturing fluids and wastewater. This contamination can have direct consequences for brook trout and their food resources. The hydrological and physical pathways are expected to result from planned (deterministic) hydraulic fracturing activities, and the chemical pathway may be triggered by both unplanned spill and leak (probabilistic) events, as well as planned discharge of treated wastewater into streams or spreading of brines on roadways.

The delineation of these pathways identifies an array of immediate research priorities. The potential relationships identified in the conceptual model (Figure 5) provide a framework of empirical relationships between Marcellus Shale drilling activities, deterministic pathways, and brook trout populations that need to be tested and verified. There is currently variation in hydraulic fracturing density within the Marcellus Shale, ranging from extensive operations in Pennsylvania and West Virginia to a moratorium on the process in New York. Opportunities exist for researchers to develop studies that verify potential relationships between drilling activities and brook trout populations, such as examining sediment impacts and brook trout responses across watersheds representing a range of well densities (Entrekin et al. 2011) or over time in watersheds with increasing levels of drilling activity. Correlative studies should also be

confirmed through experimental approaches that take advantage of paired watershed or before–after control-impact (Downes et al. 2002) designs. Tiered spatial analysis techniques can be used to assess the cumulative impacts of persistent drilling activity within nested drainage areas at a range of spatial scales (Bolstad and Swank 1997; MacDonald 2000; Strager et al. 2009). Additionally, risk assessment analyses based on biological endpoints are needed to characterize impacts of probabilistic events such as chemical spills and leaks (USEPA 1998; Karr and Chu 1997).

MOVING FROM RESEARCH TO MANAGEMENT AND CONSERVATION POLICY

Management of hydraulic fracturing activities in the Marcellus Shale is the responsibility of various permitting regulatory agencies with various scales of influence, including statewide (departments of environmental conservation/protection, departments of transportation, fish and game commissions, etc.) and regional (conservation districts, river basin commissions, etc.) entities. Though the individual policies are too numerous to describe in depth here, it is apparent that policies can be developed and refined with the support of research and monitoring programs that provide crucial data, such as a geographically finer scale understanding of brook trout distribution and population status, seasonal flow requirements for brook trout at their various life stages (Figure 6), identification and prioritization of high-quality habitat, and verification of the potential drilling impacts within the Marcellus Shale. These types of data are necessary for revising existing policies and developing new policies that are protective of brook trout populations and the stream ecosystems that support them in the face of increased Marcellus Shale drilling activities.

An example of science influencing policy that is protective of brook trout habitat is the current and proposed water withdrawal policies for the Susquehanna River Basin. The SRBC governs water withdrawal permitting for the Susquehanna River Basin region, and its policies have the potential to influence the degree to which hydrologic impacts of Marcellus Shale drilling may influence brook trout populations (SRBC 2002). The SRBC currently enforces minimum flow criteria for water withdrawals for hydraulic fracturing in coldwater trout streams to prevent low-flow impacts (Rahm and Riha 2012). The SRBC requires that water withdrawals must stop when stream flow at withdrawal sites falls below predetermined passby flows and cease until acceptable flow returns for 48 h. For small streams (<100 mile^2), passby flows are determined based on instream flow models (Denslinger et al. 1998) and are designed to prevent more than 5% to 15% change in trout habitat, depending on the amount of trout biomass the stream supports. A more general 25% average daily flow requirement is used as the passby flow for larger coldwater trout streams (SRBC 2002). This policy is expected to prevent water withdrawals from impacting habitats during low flows in summer. However, analyses of hypothetical withdrawals within the range of proposed water withdrawal permits suggest that water needs associated with Marcellus Shale drilling will impact seasonal flow needs (not just summer low flow) of small streams likely to support brook trout (DePhilip and Moberg 2010; Rahm and Riha 2012). Additionally, multiple upstream withdrawal events occurring on the same day within the same catchment may culminate in stream flows falling below the passby flow requirement. Though there is considerable uncertainty around water withdrawal estimates, accounting for cumulative withdrawal-induced low-flow effects can increase the number of days that are expected to fall below passby requirements for smaller streams by as much as approximately 100 days within an average year (Rahm and Riha 2012). Consequently, the SRBC has released new proposed low-flow protection regulations for public comment (SRBC 2012b, 2012c), based primarily on recommendations from a cooperative project between The Nature Conservancy, staff from the SRBC, and its member jurisdictions (DePhillip and Moberg 2010). The proposed SRBC flow policy uses a tiered approach to flow protection that prevents withdrawals or puts more stringent requirements in extremely sensitive or exceptional quality streams such as small headwater streams that support reproducing brook trout populations (SRBC 2012b, 2012c). This proposed policy would also provide significant flow protection for trout streams by incorporating seasonal or monthly flow variability into passby flow criteria rather than based on a single average daily flow criterion (Richter et al. 2011; Figure 6) and assessing proposed withdrawal impacts within the context of cumulative flow reductions associated with existing upstream withdrawals (Rahm and Riha 2012). However, the SRBC's proposed policy has received considerable critique from stakeholders, including the natural gas industry (SRBC 2012a). It is unclear what protections a revised water withdrawal policy will provide to streams that support brook trout habitat.

The SRBC policy is only one example of a regulatory body using scientific data to improve and refine a management policy that directly relates to potential drilling impacts on trout populations. It is crucial that policies governing hydraulic fracturing activities be likewise dynamic and subject to adaptation based on updated scientific knowledge. For example, the Pennsylvania *Oil and Gas Operators Manual* provides technical guidance for infrastructure development by identifying best management practices for sediment and erosion control and well pad, road, pipeline, and stream-crossing designs and delineates preventative waste-handling procedures to avoid unexpected probabilistic events like spills and runoff (PADEP 2001). These practices should be amended and updated as new studies refine methods to minimize impacts (e.g., Reid et al. 2004) and strategically protect or restore habitat quality or connectivity (e.g., Poplar-Jeffers et al. 2009). Furthermore, water quality data from monitoring efforts, like TU's Coldwater Conservation Corps (one of many stream survey programs that train and equip volunteers to conduct water quality testing in local streams; TU 2012) can alert regulatory agencies to failures in the probabilistic event prevention strategies that may help better characterize risks and improve waste transport and disposal procedures. For expansion of drilling in new areas, such as into New York State, regulatory agencies including the New York State Department of Environmental Conservation (NYSDEC), which is currently evaluating potential impacts of hydrologic fracturing activities

and developing a corresponding set of proposed regulations (NYSDEC 2011), should utilize the most up-to-date and complete scientific data possible from active monitoring efforts to develop best management practices that are optimally protective of natural flow regimes, habitat conditions, and water quality in high-quality streams.

Spatial analysis and visualization of well density (Figure 4) can be combined with refined understanding of brook trout habitat and population status from stream surveys and groundtruthing to prioritize and geographically focus conservation efforts. Currently the Pennsylvania Fish and Boat Commission's Unassessed Waters Program in conjunction with Trout Unlimited and other partner organizations is conducting intensive assessments of streams with unknown brook trout status: to date, this program has identified an additional 99 streams that support wild populations (Weisberg 2011). Similar efforts are being spearheaded in New York by the NYSDEC and TU (2011). Furthermore, the efficacy of regulatory policy can be bolstered by data from monitoring and research efforts that define highest priority watersheds for conservation of brook trout. Various trout-focused organizations have identified key watersheds for protection and restoration. Trout Unlimited has updated their existing Conservation Success Index (J. E. Williams et al. 2007) with a targeted analysis for Pennsylvania to integrate new data on brook trout streams and natural gas drilling threats (TU 2011b). Likewise, the EBTJV has identified an extensive set of action strategies that identify priorities on a state-by-state basis (EBTJV 2011). Results from these types of analyses can be used to identify and direct conservation efforts to key areas where Marcellus Shale drilling activities are likely to have the greatest impacts by disturbing habitat for the highest quality remaining brook trout populations.

In summary, expedient efforts to develop strategies that minimize negative impacts of Marcellus Shale drilling activities on brook trout habitat are needed. Horizontal drilling and hydraulic fracturing for natural gas extraction is likely to increase and expand from Pennsylvania and West Virginia into unexploited areas with growing pressure related to economic incentives from the oil and gas industry and the need for cheap domestic energy sources. Natural gas drilling is expected to persist in the region for several decades due to the extent of the Marcellus Shale natural gas resource and the presence of the gas-rich Utica Shale below it (P. Williams 2008). Consequently, development of adequate management and conservation strategies based on science and enforcement of policies that conserve and protect stream ecosystems supporting brook trout populations and other aquatic organisms are needed to balance energy needs and economic incentives with environmental and brook trout conservation concerns.

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Adaptive Forgetting: Why Predator Recognition Training Might Not Enhance Poststocking Survival

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ABSTRACT: *The success of current fish restocking efforts is often hampered by poor poststocking survival of hatchery-reared juveniles. As a result of hatchery selection, combined with a lack of ecologically relevant experience, hatchery-reared fishes often fail to recognize and respond to potential predators following stocking into natural waterways. One commonly proposed method to enhance potential poststocking survival is to condition hatchery-reared fishes to recognize predators prior to stocking. However, despite a wealth of laboratory and field studies demonstrating predator recognition learning in fishes, only a handful of studies have attempted to assess potential poststocking benefits, and these suggest mixed results. Our goal is to highlight possible causes of this apparent contradiction. A survey of the behavioral ecology literature highlights the exceptional degree of sophistication of predator recognition learning among prey fishes. Moreover, an emerging body of literature suggests that how long prey retain learned predator recognition is as important as what prey learn. This highly plastic retention (memory window) may confer adaptive benefits under variable conditions. Hatchery selection may result in phenotypes leading to reduced learning and/or retention of learned information. We conclude by proposing several avenues of investigation aimed at improving the success of prestocking conditioning paradigms.*

Olvido adaptativo: por qué el entrenamiento para reconocer depredadores puede no incrementar la supervivencia después del repoblamiento

RESUMEN: El éxito de los esfuerzos de repoblamiento de peces suele disminuir debido a condiciones desfavorables para la supervivencia de juveniles, provenientes de cultivo, tras prácticas de repoblamiento. Como resultado de la selección en cultivo, en combinación con la falta de experiencia en temas de ecología, los peces de cultivo a veces fallan en reconocer y responder potenciales depredadores después de haber sido introducidos, con fines de repoblamiento, a cuerpos de agua. Un método comúnmente propuesto para aumentar la supervivencia post-repoblamiento es condicionar a los juveniles de peces cultivados a que reconozcan a sus depredadores antes de la translocación. Sin embargo, pese al buen equipamiento de los laboratorios y a los trabajos en campo que demuestran la capacidad de aprendizaje de los peces para reconocer depredadores, solo unos pocos estudios se han enfocado en evaluar los beneficios potenciales post-repoblamiento y dichos estudios muestran resultados encontrados. Nuestro objetivo es subrayar las posibles causas de esta aparente contradicción. Un sondeo bibliográfico acerca de ecología conductual destaca la extraordinaria sofisticación del proceso de aprendizaje en peces para reconocer a sus depredadores. No obstante, otra parte de la literatura reciente sugiere que el tiempo que los peces retienen el patrón de reconocimiento del depredador es igualmente importante que lo aprendido por el individuo. Esta retención altamente flexible (ventana de memoria) puede conferir beneficios adaptativos ante condiciones variables. La selección mediante el cultivo puede resultar en fenotipos caracterizados por una reducida capacidad y/o poca retención de la información aprendida. Concluimos proponiendo distintas líneas de investigación cuyo propósito es aumentar el éxito del acondicionamiento previo al repoblamiento.

Hatchery-reared (HR) fishes, especially salmonids, are routinely stocked into natural waterways as part of population enhancement, recovery programs, and conservation efforts (C. Brown and Laland 2001; Salvanes and Braithwaite 2006; Fraser 2008). These recovery programs, however, are often met with limited success. Though some studies have shown that HR fish have similar poststocking survival rates as do their wild counterparts (e.g., Johnson et al. 2010), many studies point toward reduced survival among HR populations (e.g., Olla et al. 1994; Shively et al. 1996; Salvanes and Braithwaite 2006). A reduced survival may be due, in part, to the maladaptive behavioral phenotypes of HR fish, compared to their wild counterparts (C. Brown and Day 2002; Fraser 2008; Fernö et al. 2011). A growing body of research shows that hatchery-rearing, even over a little as one to two generations, is sufficient to induce significant differences in foraging (Fernö et al. 2011), growth rates (Tymchuck et al. 2007), risk-taking behavioral tactics (Sundström et al. 2004), and predator avoidance behaviors (Shively et al. 1996; Houde et al. 2010; Jackson and Brown 2011) between HR salmonids and their wild counterparts. Such differences in behavioral phenotypes may lead to stocked fish having reduced growth rates, increased predation risk, and/or reduced fitness (Huntingford 2004; Fernö et al. 2011).

Maladaptive behavioral phenotypes may arise from one of two possible mechanisms or, more likely, a combination of the two. Initially, under hatchery conditions, juvenile HR fishes lack experience with natural foraging conditions, microhabitat variability, and predation threats (Olla et al. 1998; C. Brown and Day 2002; Fernö et al. 2011). As a result of the unnatural hatchery environment, juvenile HR fishes might suffer from a lack of opportunity to learn through direct or indirect experience (Fernö et al. 2011), resulting in poorly developed or context-inappropriate behavioral phenotypes (C. Brown and Day 2002). Secondly, behavioral differences between hatchery and wild populations may be the result of genetic divergence resulting from either inadvertent selection for traits that are beneficial under hatchery conditions or the relaxation of natural selection pressures under hatchery conditions (Huntingford 2004; Fraser 2008). Jackson and Brown (2011) directly tested this hypothesis under natural conditions with juvenile Atlantic salmon (Salmo salar) originating from the same population. They compared the predator avoidance behavior of wild-caught juvenile Atlantic salmon with that of the offspring of wild-caught parents (F_1) and the offspring of parents that had spent one full generation under hatchery conditions (F_2). Jackson and Brown (2011) found the strongest predator avoidance response to a standardized predation cue among wild-caught salmon and the weakest response among F_2 salmon. Curiously, the response of the F_1 group was intermediate, suggesting that both hatchery selection and a lack of ecologically relevant experience contribute to the maladaptive behavior patterns among HR salmon.

A commonly advocated solution in a wide range of taxonomically diverse prey populations reared under artificial conditions is "life skills training" (Suboski and Templeton 1989; G. E. Brown and Smith 1998; C. Brown and Laland 2001). The idea that HR fish can be taught to recognize potential predators prior to stocking is attractive because it could allow for increased poststocking survival. Such enhanced survival would reduce the costs associated with stocking programs and potentially increase the effectiveness of population recovery efforts (Salvanes and Braithwaite 2006). However, despite considerable effort to demonstrate learning under laboratory conditions (reviewed in G. E. Brown et al. 2011a), only a few studies have attempted to demonstrate the potential benefits of prestocking predator recognition training efforts on the poststocking survival of commercially important species. These studies have provided, at best, mixed results. For example, Berejikian et al. (1999) found that though Chinook salmon (*Oncorhynchus tshawytscha*) could be conditioned to avoid the odor of an ecologically relevant predator (adult cutthroat trout, *Oncorhynchus clarki*) under laboratory conditions, this did not result in enhanced poststocking survival. Likewise, Hawkins et al. (2007) conditioned 1+ Atlantic salmon (*Salmo salar*) to recognize northern pike (*Esox lucius*) as a potential predator. Conditioned salmon survived no better when stocked into lakes where pike were the dominant predator. Conversely, D'Anna et al. (2012) conditioned white seabream (*Diplodus sargus*) prior to release and found a near doubling of poststocking survival. Likewise, Hutchinson et al. (2012) demonstrated two- to fourfold increases in poststocking survival of juvenile Murray cod (*Maccullochella peelii*) but not for juvenile silver perch (*Bidyanus bidyanus*). Thus, we are left with the question of why this type of learning may not translate to enhanced survival.

Here, we provide an overview of recent work examining chemically mediated predator recognition mechanisms in aquatic prey species and highlight the incredible degree of sophistication involved in these learning mechanisms. In addition, we examine the poorly understood aspect of retention of learned information. Finally, we conclude with some potential avenues to address the question of why prestocking training might not work to increase poststocking survival. The extent to which hatchery effects (selection + differential experience) will impact the poststocking survival and learning ability of fishes clearly depends upon the holding and breeding practices employed within hatcheries. For example, Beckman et al. (1999) found that differences in prestocking growth rate of hatchery-reared Chinook salmon was related to the likelihood of stocked smolts returning as adults. Likewise, habitat enrichment within hatchery-rearing tanks is known to enhance natural foraging patterns, possibly increasing poststocking survival (Roberts et al. 2011). For simplicity, we refer to the dichotomy of hatchery-reared vs. wild-stock fishes within the context of predator-recognition learning. Our goal here is to bring to light recent advances in the study of ecologically relevant learning mechanisms and to bridge the gap between the behavioral ecological literature and possible fisheries applications.

THE SOPHISTICATION OF PREDATOR RECOGNITION LEARNING IN FISHES

Learning, in the broadest sense, can be defined as the ability to modify behavioral response patterns based on experience (G. E. Brown and Chivers 2005). The ability to reliably assess local predation threats allows prey (including juvenile salmonids) to balance the often conflicting demands of predator avoidance and a suite of behavioral activities such as foraging and territorial defense (Lima and Dill 1990; Kim et al. 2011). This is especially difficult under conditions of variable predation risk and/or foraging opportunity (Sih 1992; Dall et al. 2005). Learning to recognize potential predators allows prey to respond only to ecologically relevant threats and to avoid expending time and energy responding to irrelevant cues. In addition, learned recognition has been shown to increase survival during staged encounters with live predators (Mirza and Chivers 2000; Darwish et al. 2005; Vilhunen 2006). Thus, under conditions of variable predation risks, learning is argued to allow prey to optimize the trade-off between predator avoidance and other fitness-related activities (G. E. Brown and Chivers 2005; Dall et al. 2005; G. E. Brown et al. 2011a).

A large body of research has investigated the mechanisms of predator recognition learning in fishes (Ferrari et al. 2010a; G. E. Brown et al. 2011c). A well-documented mechanism of learning is the so-called chemically mediated learning. Damage-released chemical alarm cues are a common feature in freshwater and marine fishes (Ferrari et al. 2010c), which are released following mechanical damage incurred during an attack by a

predator. Given the mechanism of release, these chemosensory cues are reliable indicators of predation threats (Chivers et al. 2007, 2012; Ferrari et al. 2010c). When released into the water column and detected by nearby conspecifics and/or heterospecifics, these cues may elicit dramatic, short-term increases in species-specific antipredator behavior (Ferrari et al. 2010c). Recent studies demonstrate that alarm cues convey a surprising amount of information regarding local predation threats. For example, the response intensity of many prey fishes appears to be proportional to the concentration of alarm cue detected (e.g., Dupuch et al. 2004; G. E. Brown et al. 2006, 2009). Similarly, detecting alarm cues at concentrations below that needed to elicit an observable antipredator response are known to increase the use of secondary cues (i.e., visual information; G. E. Brown et al. 2004).

When paired with the visual and/or chemical cues of a novel predator, these alarm cues can facilitate the learned recognition of a novel predator (G. E. Brown et al. 2011a). For example, when juvenile rainbow trout are presented with the paired stimuli of a conspecific alarm cue (innate unconditioned stimulus) and the odor of a novel predator (conditioned stimulus), the trout will exhibit a strong increase in predator avoidance toward the alarm cue. However, when later presented with the predator odor, the trout will increase predator avoidance, demonstrating a learned response to the previously novel predator cue (G. E. Brown and Smith 1998). Following a single conditioning trial, these learned responses may persist for several weeks (G. E. Brown and Smith 1998). Control trials, in which the predator odor is paired with distilled water, fail to elicit any evidence of learning (G. E. Brown and Smith 1998).

A wealth of studies has demonstrated that this type of direct learning is common among aquatic prey species (reviewed in G. E. Brown et al. 2011a). Recent studies have shown that juvenile Atlantic salmon are capable of such chemically mediated learning under fully natural conditions (Leduc et al. 2007). More impressive, however, is the exceptional degree of sophistication present in this learning system. For example, fathead minnows (*Pimephales promelas*) are capable of learning threat-sensitive responses (i.e., the intensity of the behavioral response is directly proportional to the level of risk; G. E. Brown et al. 2006) via this mechanism. When paired with a low concentration of alarm cue (hence low risk), prey will exhibit a similarly low-intensity response to pike odor. However, when the pike odor is paired with a high concentration of alarm cue (hence high risk), the minnows learn to exhibit a high-intensity response (Ferrari et al. 2005). Recent experiments with HR rainbow trout extend these findings, showing that when conditioned to recognize pumpkinseed (*Lepomis gibbosus*) as predation threats, trout can generalize the learned response to the odors of predators that are taxonomically related to pumpkinseed (i.e., longear sunfish, *Lepomis megalotis*) but not to those of more distantly related predators (i.e., yellow perch, *Perca flavescens*; Brown et al. 2011c). Finally, when glowlight tetras (*Hemigrammus erythrozonus*) are conditioned with a conspecific alarm cue paired with the combined odor of largemouth bass (*Micropterus salmoides*), convict cichlids (*Amatitlania nigrofasciata*), and common goldfish (*Carassius auratus*), they are capable of exhibiting increased antipredator behavior in response to individual predator odors but not the odor of a predator not included in the cocktail (yellow perch; Darwish et al. 2005). Moreover, this cocktail learning was shown to increase survival during staged encounters with live predators (Darwish et al. 2005).

Learned predator recognition may also occur via indirect learning mechanisms. Initially, predator recognition can be facilitated via the mechanism of social or observational learning. Social learning may occur when prey acquire the recognition of novel predator cues in the absence of any direct experience (Mathis et al. 1996); simply observing an experienced conspecific (or heterospecific) prey respond to a predator cue can provide sufficient information to allow learning to occur. Such social learning may allow for the rapid transmission of recognition of novel predator cues within populations (G. E. Brown et al. 1997) and has been employed under hatchery conditions to enhance the learning of context-appropriate foraging patterns (C. Brown et al. 2003; Rodewald et al. 2011). Secondly, predator diet cues may also facilitate learning. For example, fathead minnows exposed to northern pike fed a diet of minnows learn to recognize the visual cues of pike (i.e., will respond to the sight of the predator), whereas minnows exposed to pike fed an unknown diet do not respond to the sight of the pike (Mathis and Smith 1993). Likewise, the response of juvenile Arctic charr (*Salvelinus alpinus*) to predator odors is enhanced when the predators have been fed charr versus when they are food deprived (Vilhunen and Hirvonen 2003). Finally, age of individuals seems to influence their ability to learn novel predator recognition. For example, Hawkins et al. (2008) demonstrated that juvenile Atlantic salmon exhibit age-specific sensitivity to novel predator odors. Under laboratory conditions, 10- to 15-week posthatching salmon were more responsive to pike odor than were younger or older conspecifics. Moreover, 16- to 20-week posthatching salmon were better able to learn to recognize novel predator odors than were younger salmon. Hutchison et al. (2012), however, found that whereas Murray cod fingerlings can learn to recognize novel predators, subadults exhibited no evidence of learning. Combined, these findings suggest a critical ontogenetic constraint on the timing of predator recognition learning.

Together, these studies demonstrate that chemically mediated predator recognition learning is a highly sophisticated and complex mechanism allowing for an incredible degree of behavioral plasticity. Under conditions of uncertain predation threats, the ability to modify predator avoidance responses based on recent experience likely confers significant fitness advantages (Dall et al. 2005; G. E. Brown et al. 2011a). However, if learning is so critical to the survival of wild prey populations, why should prestocking conditioning not confer increased survival benefits? The answer to this question might lie in the emerging question of retention of learned information (i.e., memory).

RETENTION OF LEARNED INFORMATION

Though there is a very large body of literature demonstrat-

ing the learning abilities and ecological constraints on learning in prey organisms (reviewed in G. E. Brown and Chivers 2005; G. E. Brown et al. 2011a), surprisingly little is known about the retention of learned information. The retention of learned predator recognition varies widely among prey fishes (Ferrari et al. 2010a). For example, following a single conditioning event, HR rainbow trout conditioned to recognize a novel predator will retain a detectable response for up to 21 days (G. E. Brown and Smith 1998), though the intensity of the response wanes after approximately 10 days (Mirza and Chivers 2000). Conversely, after a single conditioning, fathead minnows retained their learned response to a novel predator cue for at least 2 months with little evidence of a decrease in response intensity (Chivers and Smith 1994). Similar studies have shown that learned foraging preferences also vary within and between populations (Mackney and Hughes 1995).

Recently, Ferrari et al. (2010a) proposed a model of "adaptive forgetting," suggesting that the retention (how long prey will exhibit an observable response) to learned information is flexible and dependent on the certainty of this information. Under natural conditions, prey must balance the need to detect and avoid predation threats and to maximize foraging and reproduction (Lima and Dill 1990). The ability to balance these trade-offs depends on the availability of accurate and reliable information regarding risk associated with potential predators (Dall et al. 2005). In turn, the reliability of learned information should impact the duration of its retention (Ferrari et al. 2010a). For example, prey may outgrow gape limits of potential predators, reducing the value of learned recognition. Exhibiting an increased predator avoidance response toward this previously learned cue would represent a cost in the form of lost energy intake. However, if the prey were still at risk to the predator, failure to respond might result in death.

Ferrari et al. (2010a) suggested a number of intrinsic (i.e., prey growth rate, behavioral tactics) and extrinsic (i.e., predictability of predation threats, predator risk level) factors that would be expected to influence the retention of learned information. This model is particularly relevant to the issue of prestocking predator recognition training because hatchery selection may influence the very factors that shape the retention of learned information. Next, we will discuss several relevant examples from our recent work.

RETENTION AND THE EFFECTS OF HATCHERY SELECTION

Personality and Retention

A growing body of literature demonstrates consistent behavioral tactics, often referred to as "shy" vs. "bold" phenotypes, in a wide range of fishes (including salmonids; Budaev and Brown 2011). Generally speaking, individuals with bold phenotypes are more likely to continue foraging under the risk of predation, return to foraging sooner following an attack from a predator, and spend more time away from shelter compared to shy conspecifics (Budaev and Brown 2011). According to the framework of adaptive forgetting (Ferrari et al. 2010a), we might expect bold individuals to retain learned predator recognition less effectively than shy conspecifics due to the reduced value placed on predator avoidance (Tymchuk et al. 2007). This is relevant to the prestocking paradigm, because hatchery-reared fish generally exhibit bolder behavioral tactics (i.e., brown trout, *Salmo trutta*; Sundström et al. 2004) and attenuated stress responses than do wild-caught conspecifics (Lepage et al. 2000), leading to potentially maladaptive behavior patterns.

Recently, we directly tested this prediction with HR juvenile rainbow trout. Juvenile trout were classified as shy vs. bold based on their latency to escape from an opaque chamber into a large test arena (a reliable method of assessing behavioral tactics; C. Brown et al. 2005; Wilson and McLaughlin 2007) and conditioned to recognize a novel predator cue (pumpkinseed odor). When tested for recognition of the conditioned cue 24 h later, there was no difference in the intensity of the learned antipredator response (Figure 1). However, when tested 9 days postconditioning, we found that bold trout no longer exhibited any evidence of retention of the learned response. Shy trout exhibited strong responses, similar to those of the day 2 testing (Figure 1). These data suggest that though it is possible to condition HR fish to recognize predators, they simply may not retain the information long enough to gain a functional benefit due to their bold behavioral phenotypes (G. E. Brown et al. in press).

Growth Rates and Retention

Another common trait within hatchery settings is increased growth rates associated with both the reliable availability of food and the relaxation of competitive pressures (C. Brown and Laland 2002; Saikkonen et al. 2011). Ferrari et al. (2010a) suggested that increased growth rates should reduce the rela-

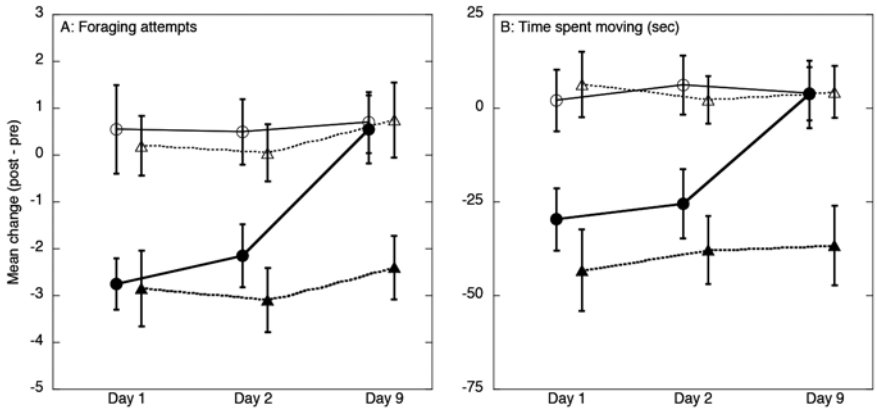


Figure 1. Mean (±SE) change in foraging attempts (A) and time moving (B) for shy (solid triangles) vs. bold (solid circles) rainbow trout conditioned to recognize pumpkinseed as a predation threat on day 1 and subsequently tested for recognition of pumpkinseed odor alone on day 2 and day 9. Shy phenotype trout exhibited significantly longer retention when compare to bold phenotype trout. Open symbols represent pseudoconditioned controls. Modified from G. E. Brown et al. (in press).

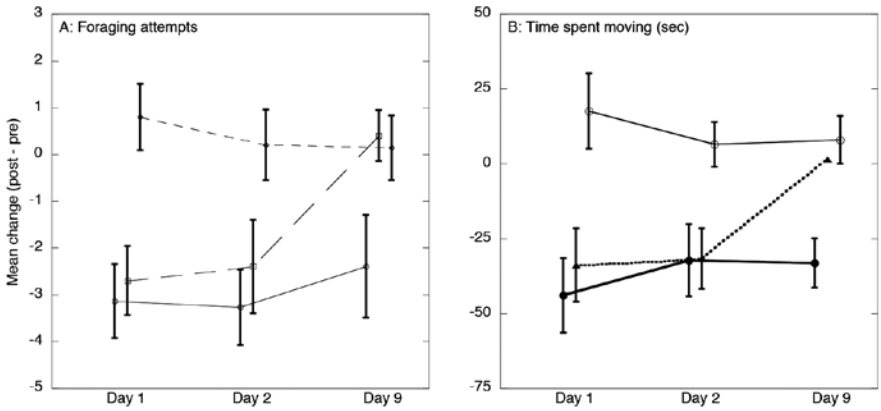


Figure 2. Mean (±SE) change in foraging attempts for juvenile rainbow trout conditioned to recognize pumpkinseed odor as a predation threat (circles) or pseudoconditioned (control; triangles) and subsequently exposed to pumpkinseed odor either 24 h postconditioning (day 2) or 8 days postconditioning (day 9). Panel A depicts results where groups of trout of similar initial mass were fed a high food (5% mbw day−1) or a low food (1% mbw day−1) ration the duration of the study. Panel B depicts results where trout of different initial masses were fed the same food ration (1% mbw day−1). Modified from G. E. Brown et al. (2011c).

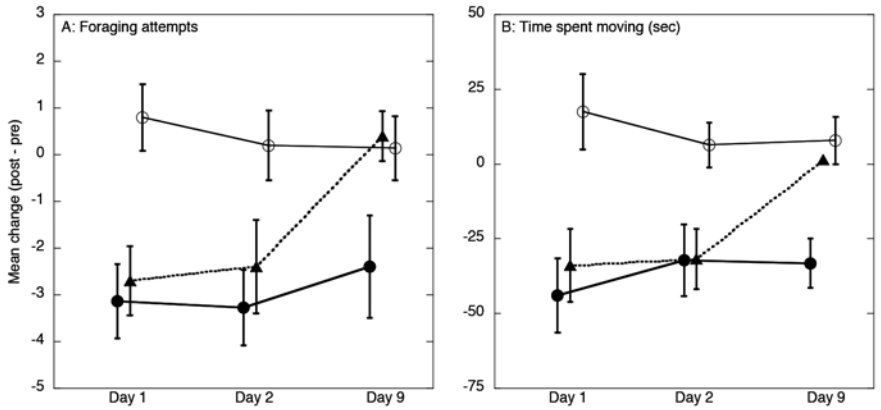


Figure 3. Mean (±SE) change in foraging attempts (A) and time moving (B) for juvenile rainbow trout conditioned with a high risk cue (circles), a low risk cue (triangles) or pseudoconditioned (squares) to recognize pumpkinseed odor as a predator cue. Modified from Ferrari et al. (2010b).

tive value of learned information. G. E. Brown et al. (2011b) tested this hypothesis under laboratory conditions with HR rainbow trout. Juvenile trout, matched for size, were reared on 1% or 5% mbw day^{-1} diets of standard trout chow for 7 days and then conditioned (or pseudoconditioned) to recognize a novel pumpkinseed predator. They were then either tested 24 h postconditioning (day 2) or held on the same 1% or 5% diet for an additional 8 days and then tested for recognition. The results suggest that though there was no difference in the intensity of the learned response between high and low food rations on day 2, only trout reared on the low food ration (low growth rate) showed any evidence of retention when tested on day 9. The observation that response intensity among conditioned trout on day 2 did not differ precludes the possibility that the observed differences on day 9 were due to hunger levels. Trout reared on the high growth rate ration were not different from pseudoconditioned controls (Figure 2A). These results were further supported by a companion study in which small (~0.6 g) and larger (~1.8 g) trout were fed the same 1% mbw day^{-1} rations and tested as above (Brown et al. 2011b). Despite a threefold difference in size, retention was similar between small and large trout (Figure 2B). Combined, these results demonstrate that growth rate at the time of conditioning influences the value of the learned information, leading to differential retention times.

Strength of Initial Conditioning

Several authors have shown that the strength of the initial conditioning event influences the overall intensity of learned predator recognition (Vilhunen and Hirvonen 2003; Ferrari et al. 2005; Zhao et al. 2006). For example, fathead minnows exhibit concentration dependent response intensities to conspecific alarm cues. Ferrari et al. (2005) found that the learned response to novel predator odors matched the intensity of the response during the initial conditioning event. More recently, Ferrari et al. (2010b) found that HR rainbow trout exhibited threat-sensitive retention of learned predator cues. Trout were conditioned to a high or low concentration of conspecific alarm cues (simulating high- vs. low-risk conditions) paired with the odor of pumpkinseeds (or pseudoconditioned) and tested for recognition. When tested for recognition 24 h postconditioning, they found that conditioned trout exhibited learned responses toward the predator cue but the intensity of response did not differ between those conditioned to high vs. low risk cues. However, when tested 8 days postconditioning, those initially exposed to the low risk cue did not retain the learned response (Figure 3).

Ontogenetic Constraints on Learning

Thought it has not been directly tested, it is possible that ontogenetic stage may also play an important role in the retention of learned predator recognition. As mentioned above, Hawkins et al. (2008) and Hutchison et al. (2012) have demonstrated age-specific propensities for chemically mediated learning in juvenile Atlantic salmon and Murray cod. Moreover, as salmonids undergo smoltification, they incur considerable physiological stress (Järvi 1990). This, combined with increased standard metabolic rates in smolts vs. nonsmolting conspecifics (Seppänen et al. 2010), might lead to a reduction in the value of learned predator recognition in favor of increased foraging demands. Several studies (Damsgård and Arnesen 1998; Skilbrei and Hansen 2004) showed a short-term reduction in growth rate and foraging during the smoltification phase but this is typically followed by an extended period of rapid growth. Such a

shift in the value of predator avoidance vs. foraging benefits could lead to a reduction in retention (Ferrari et al. 2010a, 2010b).

However, size (ontogeny) has been shown to significantly influence risk-taking tactics in juvenile coho salmon (*Onchorhynchus kisutch*). Reinhardt and Healey (1999) compared the latency to resume foraging (as a measure of antipredator response intensity) among small (~1.5 g) vs. large (~3.5 g) coho salmon reared on similar food rations. Given that maximum potential growth rate is size dependent, larger fish will be capable of realizing a higher percentage of potential growth compared to smaller conspecifics during peak growing seasons (Reinhardt and Healey 1999). Reinhardt and Healey (1999) found that among the small-sized cohort, prior growth rate had a significant positive relationship with the latency to resume foraging following exposure to a standardized predation threat, suggesting that those with lower realized potential growth were more willing to accept increased risk in order to continue foraging in accordance with the asset protection model (Clark 1994). However, they found no effect of prior growth on the risk-taking tactics of the larger cohort. According to Ferrari et al. (2010c), prey that are more willing to accept risk in order to continue foraging (i.e., bold) should show reduced retention periods compared to more risk averse individuals. Thus, potential for growth influencing risk-taking tactics (asset protection) rather than actual growth (G. E. Brown et al. 2011b) may also shape retention.



Photo 1. Behavioral observations of juvenile Atlantic salmon in the Catamaran Brook, New Brunswick. The orange markers (upper left) indicate foraging territories of individual salmon. Photo Credit: G. E. Brown.



Photo 2. Mesh enclosures anchored in the Catamaran Brook, New Brunswick. Enclosures can be stocked with tagged salmon and allow for long-term studies of behavior under natural conditions. Photo Credit: C. K. Elvidge.

Implications for Prestocking Conditioning

Taken together, we see that the mechanism of chemically mediated predator recognition learning is an incredibly complex and sophisticated system, allowing for the acquisition of complex, context-specific behavioral response patterns within a wide variety of aquatic prey species. Moreover, an emerging field of research suggests that the question of how long to retain learned information is just as important to prey species as is the question of what to learn. Clearly, both learning and retention are highly plastic processes, shaped by environmental variability. If predator recognition learning is to result in increased poststocking survival, as suggested by a variety of authors (Suboski and Templeton 1989; C. Brown and Laland 2001; Fernö et al. 2011), we should revisit the design of prestocking conditioning paradigms in light of the results presented above. Next, we suggest a number of possible avenues for future studies. Many of the topics discussed below have

previously been considered in the context of hatchery practices with an aim to enhance growth, quality, and survival, as well as the effectiveness of hatchery practices as a conservation tool (i.e., Sharma et al. 2005; Paquet et al. 2011). Thus, we limit our discussion to the relevance toward life skills training. Any findings must be considered in light of current best practices within the hatchery setting.

POSSIBLE AVENUES FOR FUTURE RESEARCH

One possibility to overcome this potential retention issue associated with prestocking conditioning would be to increase the strength of the initial conditioning event. Increasing the number of conditioning events may strengthen the initial learning and hence extend the retention of prestocking conditioning. Vilhunen (2006) found that HR Arctic charr exposed to four sequential conditioning events exhibited stronger learned responses than those conditioned a single time. Moreover, multiple conditioning events enhanced survival during staged encounters with predators. Typically, prestocking training studies have actively conditioned HR salmonids once or twice. It is possible that multiple conditioning events would extend the duration of retention, allowing for increased poststocking benefits. Likewise, based on the findings of Ferrari et al. (2010a), increased concentrations of alarm cues, indicating higher risks, should increase the strength of the initial conditioning. A recent study by Ferrari et al. (2012) demonstrated that woodfrog tadpoles (*Rana sylvatica*) that have been conditioned to recognize a novel predator odor four times retained their learned response longer than those conditioned once. This could combine with the potential benefits of social learning (C. Brown et al. 2003; Vilhunen et al. 2005).

A potential difficulty associated with repeated conditioning might be that HR fish may habituate to the predator odor. Though Vilhunen (2006) found that repeated conditionings enhanced the strength of learning, Berejikian et al. (2003) suggested that HR Chinook salmon may habituate to repeated exposures to the predator odor. There are, however, several differences between these two studies, the most relevant of which include the fact that Berijikian et al. (2003) tested Chinook salmon that were roughly twice the size as the Arctic charr tested by Vilhunen (2006). The observed differences could be related to species-specific differences in learning abilities or ontogenetic effects. Additional work is needed to examine the potential limitations associated with habituation.

A second potential avenue would be to reduce the latency between conditioning and stocking. In-stream or near-shore enclosures could be used to hold stocked fish prior to release. Such enclosures would expose HR salmonids to natural flow and drift regimes and would allow for acclimation prior to release. Large groups could then be conditioned and released. Recent work by Olson et al. (2012) suggested that mass conditioning may allow for the effective prestocking conditioning of HR fishes. Enclosure conditioning could also take advantage of potential social learning (C. Brown et al. 2003; Vilhunen et al. 2005; D'Anna et al. 2012). Vihunen et al. (2005) demonstrated that the effectiveness of social predator recognition learning is greatest when a relatively small number of experienced prey are housed with naïve prey.

Third, as described above, growth rate at the time of conditioning appears to influence retention of acquired predator recognition in at least one HR salmonid. Studies are needed to determine the potential effectiveness of placing HR salmonids on a restricted food ration prior to stocking. For example, HR stocks fed with on-demand feeders could be switched to fixed-ration feeders. Limiting the available foraging opportunities for a short time frame (a few days) may have an impact on retention without increasing stress or competition among stock populations (Ashley 2007).

Fourth, a limited number of studies examining the potential benefits of prestocking conditioning on postrelease survival have been conducted on smolts. Additional studies focused on presmolt life history stages are needed. Though it is clear that under laboratory conditions, smolts can indeed acquire recognition of novel predators (i.e., Berejikian et al. 1999), the increased physiological stress associated with smoltification and migration (Järvi 1990) may function to reduce the value of learned information. It is possible that young-of-the-year fry would exhibit longer retention periods, allowing for potential poststocking survival benefits.

Fifth, as mentioned earlier, HR fish may exhibit maladaptive or poorly developed foraging behavior in addition to impaired predator recognition. Several authors (i.e., Brown and Laland 2002; Rodewald et al. 2011) have successfully employed social learning and/or environmental enrichment to encourage context-appropriate foraging behavior in HR fishes prior to stocking. Under natural conditions, prey must balance the need to forage and avoid predators (Lima and Dill 1990). As such, there is a strong interaction between the two suites of behaviors. Combining context-appropriate foraging and predator recognition into an overall life skills training approach (C. Brown and Laland 2001) may further enhance the poststocking survival of HR fishes. In addition, as described above, prey can be conditioned to recognize multiple predators simultaneously (i.e., Darwish et al. 2005) and can generalize learned recognition across predators (i.e., G. E. Brown et al. 2011c). Learning multiple predators' cues at the same time or generalizing across ecologically relevant predators would further increase the ability of HR fishes to balance foraging—predator-avoidance tradeoffs—and may enhance poststocking survival.

The final issue that needs careful consideration is the habitat characteristics of both the conditioning environment and the place where the fish are to be released. Interactions between habitat characteristic and learning are at their infancy, but there are a few noteworthy studies that should provide us with issues to consider. For example, Gazdewich and Chivers (2002) conditioned minnows to recognize yellow perch as a predator and then staged encounters in two different habitat types. There was a clear effect of the predator training on prey survival, but

this was only evident when the encounters were staged in one habitat type. Considering the pre- and postconditioning environment may be crucial for the success of training programs. In another study, Smith et al. (2008) conditioned rainbow trout to recognize a novel predator odor at either pH 6.0 or 7.0. A week later, the fish that were tested for recognition of the odor at the pH used during conditioning displayed antipredator responses, whereas those tested at the other pH did not. This study points to the need to consider the water quality parameters of the water body in which the fish are released. A simple change in pH may render learning ineffective and the training programs a waste of valuable resources.

Taken together, the research described in our review suggests that more research is needed to investigate the potential benefits associated with prestocking predator recognition training. The behavioral ecology literature suggests that learning is an adaptive phenotype that confers significant benefits under conditions of variable predation risk. Moreover, this literature suggests that the question of how long learned information is retained is equally as important as what information is learned.

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W.F. Thompson Award for Best Student Paper Published in 2011

Nominations are open for the W.F. Thompson Award, which will be given by the American Institute of Fishery Research Biologists (AIFRB) to recognize the best student paper in fisheries science published during 2011. The award will consist of a check for $1000, a certificate, and a one-year membership in AIFRB at an appropriate level. The requirements for eligibility are as follows:

(1) the paper must be based on research performed while the student was a candidate for a Bachelor's, Master's, or Ph.D degree at a college or university in the Western Hemisphere;

(2) the results of the research must have been submitted to the recognized scientific journal in which it was eventually published, or to the editor of the book in which it was eventually published, within three (3) years of termination of student status;

(3) papers that are considered for the award must be concerned with freshwater or marine biological resources;

(4) the paper must be in English; and

(5) the student must be the senior author of the paper.

Nominations may be submitted by professors or other mentors, associates of the students, or by the students themselves.

The deadline for receipt of nominations is January 31, 2013. The nominations should be sent to the Chairman of the W.F. Thompson Award Committee, Dr. Frank M. Panek, USGS-Leetown Science Center, 11649 Leetown Rd, Kearneysville, WV 25430 (email: fpanek@usgs.gov).

Each nomination must be accompanied by a copy of the paper (unless it is easily available on the internet) and a résumé.

The papers will be judged by knowledgeable subject matter reviewers selected by the Chairman and members of the Committee on the basis of contribution to fisheries science, originality, and presentation.

The National Ecological Observatory Network: An Observatory Poised to Expand Spatiotemporal Scales of Inquiry in Aquatic and Fisheries Science

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ABSTRACT: *Large spatiotemporal-scale fisheries research amid pervasive environmental change requires scientific resources beyond the capabilities of individual laboratories. Here we introduce the aquatics program within a novel institution, the National Ecological Observatory Network (NEON), poised to substantially advance spatiotemporal scales of inquiry in fisheries research. NEON will collect high-quality data from sites distributed throughout the United States, including Alaska, Hawaii, and Puerto Rico, for 30 years. Data products will include hundreds of metrics that comprehensively quantify the biological, chemical, and hydrogeomorphic attributes of streams, lakes, and rivers in the observatory network. Coupling observations from NEON terrestrial, atmospheric, and airborne programs will facilitate unique inquiries in ecohydrology. All NEON-generated data will be rigorously quality controlled and posted to an entirely open-access web portal. Proposals that expand the observatory scope through additional observations, sites, or experiments are encouraged. Thus, NEON represents an unprecedented and dynamic resource for fisheries researchers in the coming decades.*

La red del Observatorio Ecológico Nacional: un sistema listo para expandir la escala espacio-temporal de la investigación en la ciencia acuática y pesquera

RESUMEN: La investigación pesquera en grandes escalas espacio-temporales, dentro de un ambiente cambiante, requiere de recursos científicos que van más allá de las capacidades de laboratorios individuales. En la presente contribución se introduce el programa "aquatics" concebido en el seno de una institución de reciente formación, el Observatorio Ecológico Nacional (NEON) que fue diseñado para mejorar de forma sustancial la escala de investigación espacio-temporal de las ciencias pesqueras. NEON recolectará datos de alta calidad, dentro de un periodo de 30 años, de distintos sitios distribuidos a lo largo de los Estados Unidos de Norteamérica, incluyendo Alaska, Hawái y Puerto Rico. Los datos incluirán cientos de medidas que cuantifican los atributos biológicos, químicos e hidrogeomorfológicos de arroyos, lagos y ríos que abarca el observatorio. El acoplamiento de observaciones de los programas terrestres, atmosféricos y aéreos de NEON facilitará la investigación eco-hidrológica. Todos los datos generados por NEON pasarán por un riguroso control de calidad y serán puestos a disposición del público en general en un portal de internet. Se exhortan aquellas propuestas que, a través de la adición de observaciones, sitios o experimentos, estén encaminadas a expandir el ámbito del observatorio. Así, NEON representa un recurso, dinámico y sin precedentes, para los investigadores pesqueros en las próximas décadas.

INTRODUCTION

Understanding the multiscaled spatial and temporal processes that structure aquatic ecosystems is a fundamental challenge in fisheries management and conservation. For example, the suite of physical controls that shape habitat templates in rivers operate with observable signatures spanning approximately 15 orders of magnitude across time and space (Minshall 1988), whereas processes occurring among and within interacting populations of organisms exhibit an arguably equivalent degree of spatiotemporal heterogeneity (Fausch et al. 2002). Complicating matters further, freshwater and terrestrial ecosystems are inexorably linked through nutrient (Marcarelli et al. 2011), prey (Wipfli and Baxter 2010), and water subsidies also operating at variable spatiotemporal scales. Finite resources inevitably limit the spatial and temporal extent of virtually all ecological studies, resulting in a high likelihood of overlooking or mischaracterizing important patterns and processes (Cooper et al. 1998). Such knowledge gaps inevitably lead to uncertainties when developing science-informed management decisions.

Applying broad-scale spatiotemporal data often proves to be an effective means of addressing such challenges. For instance, long-term data sets from widely distributed locations have been recently used to highlight greater than expected phenological responses of plants to climate change (Wolkovich et al. 2012), demonstrate spatially pervasive trends of rising water temperatures in streams and rivers (Kaushal et al. 2010), and evaluate the current status of marine fisheries on a global spatial scale (Worm et al. 2009). Yet the information resources that led to such findings represent the exception in ecology, with the majority of collected data within the field remaining proprietary and inaccessible despite the clear need for openness in

such a collaborative, interdisciplinary science (Reichman et al. 2011). Furthermore, even when data are freely available, poorly documented metadata, incomplete provenance, and/or inconsistent methodology can render comparability among locations or across time spans impossible (Peters 2010).

Fortunately, several recently initiated large-scale environmental observatories will soon expand scales of inquiry in disciplines with ties to fisheries science for all researchers. Such networks aim to freely provide multidecadal data records collected using standardized methodology to allow trend comparisons among widely dispersed sites. For instance, the National Science Foundation (NSF)-supported Ocean Observatory Initiative will begin publishing 25 years worth of open-access multivariate oceanographic data from a network of deepwater and coastal arrays dispersed throughout the western hemisphere starting in 2015 (Cowles et al. 2010). Another NSF-funded initiative, the Critical Zone Observatory (CZO; http://www.criticalzone.org), freely publishes hydrologic, chemical, and physical data from the vadose zones of seven locations throughout the United States and Puerto Rico (Anderson et al. 2008; Lin et al. 2011). Lake ecologists may access an unprecedented catalog of information amassed by the Global Lake Ecological Observatory Network (GLEON; gleon.org), a grassroots network of scientists integrating scalable environmental data from lakes around the world (Hanson 2008; Kratz et al. 2006).

Here we introduce an observatory poised to become a valuable resource for fisheries scientists: the National Ecological Observatory Network (NEON). The observatory is an NSF-funded project currently being constructed by an independent 501(3)(c) nonprofit corporation (NEON, Inc.; headquartered in Boulder, Colorado). The explicit mission of NEON is to enable continental-scale ecological forecasting (i.e., identifying broad-scale patterns across North America and using these to help predict future trends) by providing infrastructure and high-quality, standardized data collected throughout the United States, including Alaska, Hawaii, and Puerto Rico. Specifically, NEON was explicitly designed to address Grand Challenge questions in the environmental sciences put forth by the National Research Council (NRC 2001). NEON-generated data are thus strategically intended to provide standardized observations and experimental data to increase understanding of how (1) climate change, (2) land use change, and (3) invasive species interact to impact (1) biogeochemical cycles, (2) biodiversity, (3) ecohydrological processes, and (4) the spread of infectious diseases (Figure 1; NEON 2011).

During the scheduled 30 years of operation, NEON will archive and provide open access to more than 600 data products. Parameters will range from standard descriptive field measurements, such as indicators of water quality (e.g., NO_3 concentrations, total organic matter, and acid neutralizing capacity) to complex metrics derived from multiple variables (e.g., stream metabolism, fish biodiversity, NO_3 flux). Each measurement will be subjected to a rigorous quality assurance/quality control check. All observatory-generated data will be posted to an open-access web portal for research community and general public use. NEON will operate in 60 sites distributed among 20 ecoclimatic domains selected to maximize objective representation of

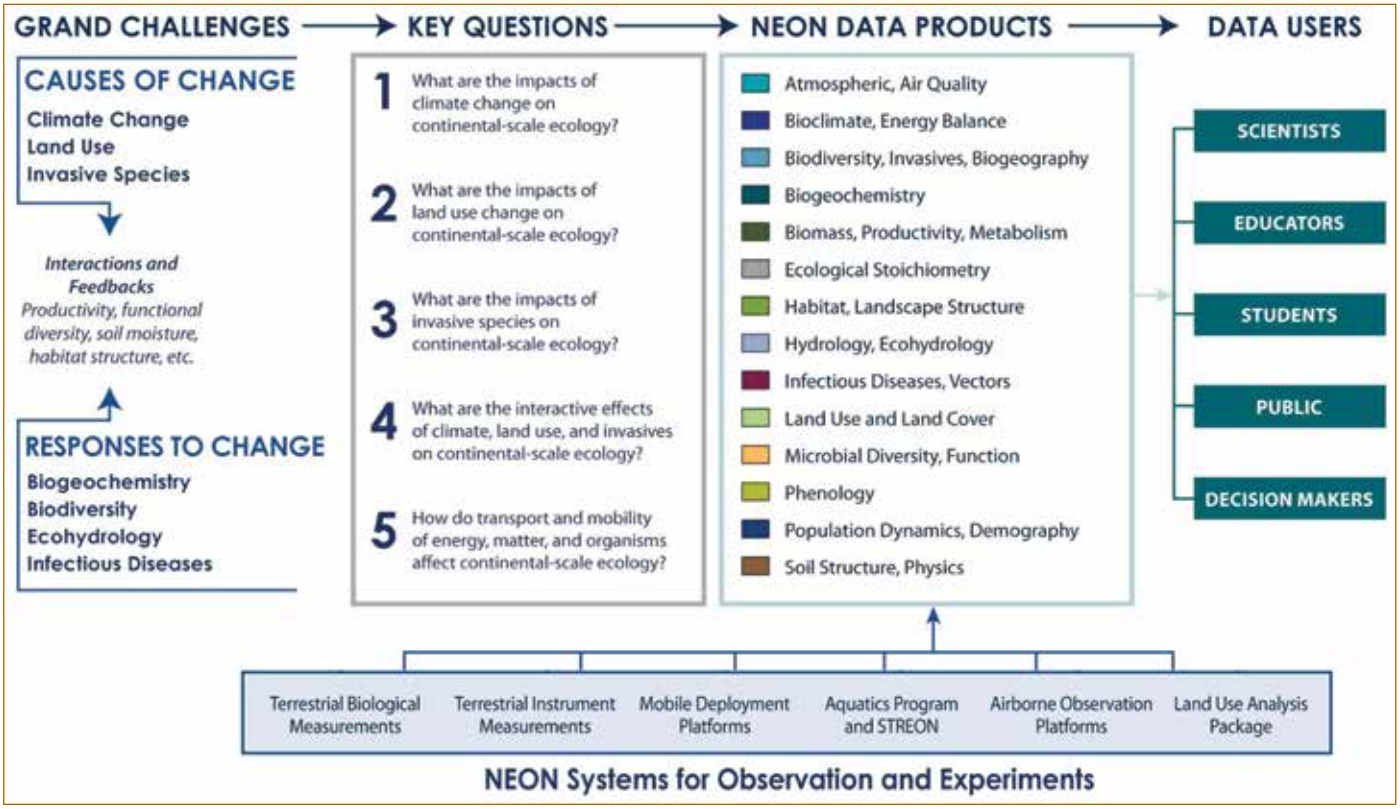


Figure 1. The theoretical basis of the NEON observatory. National Resource Council (NRC) Grand Challenges in environmental sciences have alluded to key questions that NEON data products are meant to help multiple communities address.

continental-scale environmental variability (Keller et al. 2008). The observatory is also a platform upon which researchers identifying an impetus for additional data or seeking to use NEON infrastructure for novel experiments are encouraged to apply for external funding to support their work.

Within NEON, an Aquatic Program will implement a sampling regime for 212 data products from 36 wadable streams, nonwadable rivers, and lakes throughout the United States. The Aquatic Program within NEON aims to address NRC-posited Grand Challenges in aquatic ecosystems with the exception of infectious disease dynamics. Aquatic data will include quantitative metrics characterizing diversity among multiple biological assemblages (fish, invertebrates, macrophytes, algae, and periphyton) and comprehensive biogeochemical, hydrologic, and geomorphic data. The following sections provide an overview of the data products to be derived by the NEON Aquatic Program and how they stand to benefit fisheries scientists. Because of the number of parameters to be collected, a comprehensive description of all planned data products would reach beyond the scope of this article. However, a full, descriptive list of planned data products may be freely accessed online (Keller 2010; Keller et al. 2010).

BIOLOGICAL DATA

Providing comprehensive data that enable the detection of long-term trends in biological assemblages among North American ecosystems represents a fundamental NEON goal. Data products derived from NEON biological collections in aquatic sites will include the diversity, richness, relative abundance, and spatial distribution of microbes, algae, aquatic plants, macroinvertebrates, and fishes. Individual weights and lengths of fishes will also be quantified, with the exception of sensitive species or populations that prohibit such handling. NEON field crews will collect microbial biofilm, algal, and benthic macroinvertebrate community samples two to three times per year and fish sampling will occur once per year in streams and lakes. Zooplankton samples will also be collected in all lakes. Sampling regimes for fish will consist of electrofishing, gill netting, and/or minnow traps depending on site characteristics. During the 30-year period of NEON operations, special attention will be paid to invasive species and data will denote when organisms are not native. Riparian vegetation surveys will be undertaken at each site once per year during peak leaf out. Finally, phenologically important dates associated with riparian vegetation (leaf out, fall, and senescence) that dictate patterns in evapotranspiration and associated trends in stream hydrology will be recorded at each site.

In addition to biological data collected using conventional methodology, NEON will help advance molecular techniques that catalog species and improve biomonitoring efforts. NEON will work with existing partners, including the United States Environmental Protection Agency and Barcode of Life Datasystems, to develop novel DNA barcode databases (Hajibabaei et al. 2007) for select aquatic and terrestrial taxonomic groups that are morphologically difficult to distinguish and speciose. In aquatic ecosystems, a subset of benthic macroinvertebrates will be targeted for DNA barcoding. Though the initial target aquatic taxa for DNA barcoding has yet to be determined, the group will likely possess difficult taxonomic attributes, a ubiquitous distribution and significant potential for biomonitoring applications, such as nonbiting midges (Chironomidae; Raunio et al. 2011).

CHEMICAL AND BIOGEOCHEMICAL DATA

Water quality in aquatic ecosystems is strongly integrated with surrounding terrestrial and atmospheric environments through multiple spatiotemporally heterogeneous processes (Williamson et al. 2008). Such relationships influence fish habitat, water quality, and ecosystem services, though fish may simultaneously shape water chemistry through nutrient transport, via ecosystem engineering (Moore 2006), and by creating biogeochemical hotspots (McIntyre et al. 2008). NEON will provide continuous and discrete chemical data of surface water (up to 35 parameters) at aquatic sites via in situ sensors and water samples collected up to 26 times per year. At lake sites, NEON water chemistry samples will span locations across lake surfaces and at multiple depths to quantify epilimnetic and hypolimnetic processes. These observations will help to define the seasonality of chemical parameters such as total and dissolved nutrients, cations, and anions. Isotopic ratios (i.e., δN^{15}, O^{18}, S^{34}, and C^{13}) in detritus, surface and subsurface water, particulate organic matter, and primary producer samples will also be collected to structure food webs and quantify links between chemical and biological processes and among environments. Because benthic zone sediments act as source, sink, or transformation centers of biogeochemical cycles, NEON will quantify sediment chemistry (up to 23 parameters including dissolved nutrients, cations, and anions) at least annually at all aquatic sites. Complementary metrics pertaining to grain size and structure will help determine sorption and oxygen depletion potentials. At sites where the likelihood of metal contamination is considered significant, NEON will measure sediment and water column metal concentrations. In addition to data derived from grab samples, continuous monitoring sensors will measure parameters such as turbidity, pH, conductivity, dissolved oxygen, temperature, and select nutrients, providing valuable real-time information on the chemical dynamics that affect aquatic organisms.

Aquatic chemistry parameters will also include in-house calculations of high-order biogeochemical metrics. NEON will produce measurements of whole-stream metabolism in wadable streams, which is a key indicator of processes that couple aquatic, terrestrial and atmospheric environments (Carpenter et al. 2005). Changes in land use and subsequent nutrient export from surrounding ecosystems can influence metabolism in receiving waters, ultimately impacting primary production and biological oxygen demand (Mulholland et al. 2001). In some cases, excessive nutrient inputs elevate primary productivity to rates that induce eutrophication, oxygen depletion, and fish kills (Dybas 2005). Given the value of metabolism as an integrator of environmental change, NEON will continuously quantify metabolism in wadable stream sites using a two-stage oxygen-depletion method. Associated data products will in-

clude relationships between discharge and stream reaeration rate coefficients, which will enable the calculation of continuous rates of gross primary production and ecosystem respiration per unit channel area and length. Other high-order biogeochemical metrics to be quantified by NEON include flux estimates for nitrogen, phosphorus, and carbon.

HYDROLOGIC, GEOMORPHIC, AND GROUNDWATER DATA

Climate models indicate that global changes in hydrologic cycles are imminent and will significantly affect aquatic ecosystems worldwide. In northeastern North America, heavy precipitation events are predicted to occur more frequently, whereas in the arid southwest precipitation is anticipated to decrease (Solomon et al. 2009). Severe precipitation events may induce water quality degradation in small streams and lakes, because greater fractions of water budgets could potentially be transmitted via overland flow. Such events impact the thermal attributes of aquatic ecosystems: groundwater infiltration is thermally consistent, whereas the temperature of water delivered during events as overland flow may be highly variable (Brown and Hannah 2008). Pulse- and press-dynamic changes in precipitation, water temperature fluctuations, and hydrology associated with climate change will impact the reproductive success of many fishes (Daufresne and Boët 2007). NEON will continuously record stream stage and calculate instantaneous discharge at all wadable stream sites. Additionally, aquatic sites (including lakes) will be instrumented with a network of up to eight riparian monitoring wells (≤30 m deep) to quantify local groundwater contributions at locations where such infrastructure is feasible. Sensors deployed in wells will provide near-continuous data on groundwater level, temperature, and conductivity. The well network will be spatially designed to capture coverage of influent–effluent groundwater chemistry, hydraulic gradients, and flow directions. Coupling NEON biological and biogeochemical attributes with sensor-derived groundwater well, in-stream surface water, and atmospheric/meteorological station data will allow researchers to conduct unprecedented analyses in ecohydrology.

Morphology surveys will be conducted annually to monitor changes in aquatic site physical attributes. At each stream and river site, NEON typically secures access to conduct research within a 1,000-m reach, and morphology surveys will cover this entire extent. Morphological data products in wadable stream systems will include channel attributes such as slope, sinuosity, and the relative linear extent of specific habitat types (i.e., pools, riffles, and runs). Features will be mapped with respect to fixed coordinate systems to assess questions such as whether and how channel attributes evolve over time. Additionally, the abundance, location, and mobility of large woody debris (fundamentally important to aquatic ecosystems; Gregory et al. 2003) will be quantified during morphology surveys. In lakes, detailed bathymetry surveys will be conducted using acoustic technology with high-precision differential Global Positioning Systems.

ATMOSPHERIC, TERRESTRIAL, AND REMOTELY SENSED DATA

NEON data collected outside of aquatic systems will likely also prove a valuable resource in many fisheries science applications. Terrestrial NEON data products consist of physical, chemical, and biological data, including soil metrics, evapotranspiration, phenological attributes (such as leaf senescence and emergence), and biochemical vegetation parameters. Such characteristics directly influence hydrologic cycles and water quality; thus, NEON data will enable investigative efforts relating terrestrial dynamics to hydrogeomorphic attributes in aquatic ecosystems. NEON will quantify stable isotope data signatures from multiple biotic and abiotic components of terrestrial and atmospheric environments. Consequently, stable isotope-based modeling of energy and material subsidies between terrestrial and aquatic food webs, an important phenomenon in both systems (Paetzold et al. 2005; Wipfli and Baxter 2010), will be possible across the network. NEON will collect a comprehensive suite of high-resolution data on atmospheric parameters from tower infrastructures, including total and photosynthetically active solar radiation, deposition, and wind speed/direction. These data may be used to quantify atmospheric controls on the physicochemical attributes of NEON aquatic ecosystems. Additionally, the NEON tower infrastructure will measure the chemical composition of dust and precipitation, thereby facilitating studies investigating deposition impacts on primary productivity in lake and marine ecosystems (Miller et al. 2007; Elser et al. 2009).

Data products will also include remotely sensed information derived from an Airborne Observation Platform (AOP). NEON will collect spectroscopic, photogrammetric, and light detection and ranging (LiDAR) data from flights deployed once annually over all sites in each domain. AOP observations will be converted to multiple high-order data products, such as land cover, canopy moisture, chemistry and structure, and disturbance metrics. These remotely sensed data are meant to bridge scales between satellite and terrestrially derived data. Integrating such information with aquatic and terrestrial observations should facilitate unprecedented analyses in watershed science.

STREON—THE FIRST NEON NETWORK EXPERIMENT

As mentioned above, NEON encourages proposals submitted by external scientists who use observatory facilities to conduct novel experiments. The first among these will be the Stream Experimental Observatory Network (STREON), an experimental program that will serve as a long-term assessment of stream ecosystem responses to drivers of environmental change (eutrophication and the extirpation of large-bodied organisms). STREON will consist of two treatments: (1) the nutrient most likely limiting local primary production (nitrogen or phosphorous) will be enriched by 5× ambient concentrations and (2) large-bodied organisms such as fish and amphibians will be electrically excluded from patches of benthic habitat (sediment baskets) during an annual 8- to 12-week period (Figure 2). Ad-

ditionally, the likely nonlimiting nutrient (nitrogen or phosphorus) will be chronically added at an N:P ratio of 20:1. Nutrient enrichment treatments will be applied immediately downstream of the regular aquatic NEON reach in 10 sites (Table 1, Figure 2), and consumer exclusion apparatuses (and control replicates) will be deployed in both reaches. Data associated with STREON will include all standard NEON aquatic site measurements collected in both reaches. Additionally, sediment baskets linked to the consumer exclusion treatment will be incubated in closed recirculation chambers to quantify benthic metabolism and nutrient uptake.

Past chronic nutrient enrichment experiments have demonstrated distinct temporal thresholds of whole-ecosystem effects and elevated fish growth rates in treatment reaches (Benstead et al. 2007), and studies similar to the consumer exclusion component have revealed how fishes and other large-bodied organisms induce trophic cascades and/or serve as ecosystem engineers (Greathouse et al. 2006). What renders STREON unique from past efforts is the scope: the experiment will run over a 10-year period in 10 geoclimatically distinct streams across the continent. STREON will operate using standardized data quality assurance procedures to ensure that the experiment is as consistent as possible among sites. As with all NEON-generated information, STREON data will be open access, quality assured/quality controlled and available to the public via a web portal.

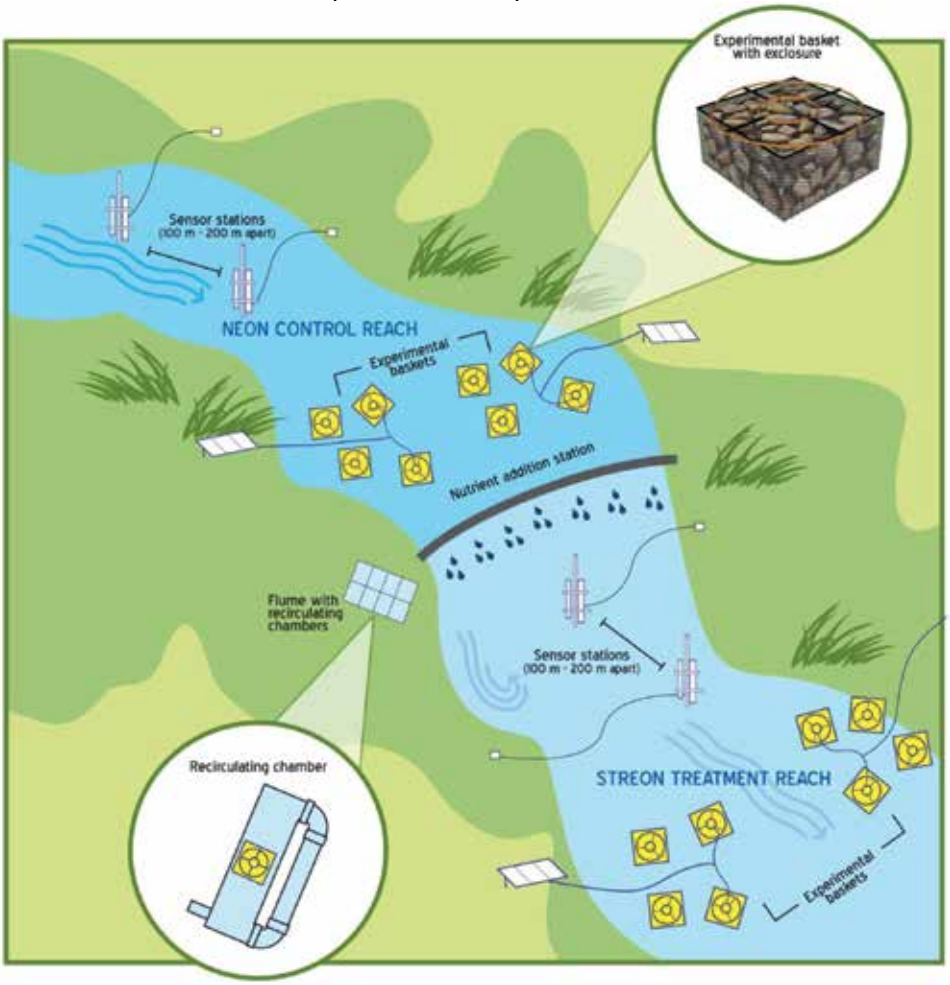


Figure 2. Experimental design of the STREON program at a typical site.

Metric and Protocol Development

The metrics to be collected and posted by NEON were specifically selected to help address NRC Grand Challenges in the environmental sciences and were identified during the planning and design phases of NEON development. From 2005 to 2011, NEON held multiple workshops and meetings intended to solicit recommendations on metric selection from external researchers in various subdisciplines of ecology. The resulting comprehensive suite of data products to be collected may be found in Keller (2010) and Keller et al. (2010). However, the NEON suite of data products will not necessarily remain static during the 30 years of operations: researchers may apply for funding (through agencies external to NEON) to expand the scope of data products that NEON collects (explained further in The NEON Structure: Current and Future section below).

For each NEON-generated data product, including all described in the preceding sections, specific protocols defining field and laboratory procedures will be written by NEON staff ecologists and peer-reviewed by active members in the research community. Protocol methodology will attempt to outline the best-known sampling practices for NEON field technicians. Preliminary protocol drafts are distributed to a voluntary working group of scientists external to NEON for review. Working group members possess the expertise required to assess such protocols and include scientists from academia, government agencies, and nonprofit organizations. For example, the aquatics technical working group reviews all aquatics program protocols and is comprised of 18 aquatic ecologists from nine universities or colleges, three federal agencies, and two nonprofit research institutions (currently active members of all working groups are listed on the NEON website). Finalized protocols will be made available to the community as open-access online resources so that researchers wishing to apply NEON methodology to maximize the comparability of data they collect may do so.

Protocols are developed to maximize data comparability among sites. Wherever possible, NEON personnel will apply identical methodology across sites. Procedures applied will represent those most appropriate for the setting where local environmental conditions significantly affect the efficacy of a certain method. For instance, when sampling benthic macroinvertebrates, Surber samplers will be used in mid- to high-gradient streams with hard substrates, whereas sites with sandy or silty substrates will be sam-

TABLE 1. NEON candidate aquatic sites and examples of fish species found in these water bodies. Sites listed are pending land use agreements (for site updates visit the NEON website). Numbers in the first column correspond to those illustrated in Figure 4. Italicized stream names denote sites in the STREON program.

Site	Name, State	Watershed area (km2; lotic systems) or surface area (ha; lakes)	Fish community attributes at site
1	West Branch Bigelow Creek, MA	0.3	No fishes present
2	Sawmill Brook, MA	4.0	No fishes present
3	*Baisman Run, MD*	1.7	Six species including brook trout (Salvelinus fontinalis), rosyside dace (Clinostomus funduloides), and longnose dace (Rhinichthys cataractae)
4	Posey Creek, VA	2.2	Currently unknown, but likely mottled sculpin (Cottus bairdi), creek chub (Semotilus atromaculatus), and blacknose dace (Rhinichthys atratulus)
5	Suggs Lake, FL	31.5	Fourteen recorded species, including spotted gar (Lepisosteus oculatus), bowfin (Amia calva), and warmouth (Lepomis gulosus)
6	Barco Lake, FL	10.1	Warmouth, largemouth bass (Micropterus salmoides), and bluegill (Lepomis macrochirus)
7	Ichawaynochaway Creek, GA	2,683.2	Fifty recorded species including goldstripe darter (Etheostoma parvipinne), shoal bass (Micropterus cataractae), and spotted bullhead (Ameiurus serracanthus)
8	*Río Cupeyes, PR*	11.3	American eel (Anguilla rostrada), mountain mullet (Angonostomus monticola), and bigmouth sleeper (Gobiomorus dormitor)
9	Río Guillarte, PR	11.9	Currently unknown; likely similar to Río Cupeyes
10	Lake Clara, WI	27.4	At least five species characteristic of north-temperate lakes, including yellow perch (Perca flavescens), largemouth bass, and northern pike (Esox lucius)
11	Pickerel Creek, WI	34.9	Currently unknown
12	*Kings Creek, KS*	12.4	Twenty recorded species including orangethroat darter (Etheostoma spectabile), orangespotted sunfish (Lepomis humilis), and shorthead redhorse (Moxostoma macrolepidotum)
13	McDowell Creek, KS	214.4	Thirty-six recorded species, including carmine shiner (Notropis percobromus), southern redbelly dace (Phoxinus erythrogaster), and longnose gar (Lepisosteus osseus)
14	LeConte Creek, TN	9.1	Brook trout and mottled sculpin (Cottus bairdi)
15	*Walker Branch, TN*	0.4	Creek chub and western blacknose dace (Rhinichthys obtusus)
16	Black Warrior River, AL	15,159.3	One hundred twenty-six recorded species including Tuskaloosa darter (Etheostoma douglasi), redeye bass (Micropterus coosae), and black redhorse (Moxostoma duquesnei)
17	Lower Tombigbee River, AL	47,102.4	One hundred twenty-one recorded species, including paddlefish (Polyodon spathula), river redhorse (Moxostoma carinatum), and crystal darter (Ammocrypta asprella)
18	*Mayfield Creek, AL*	17.0	Currently unknown, but could include >25 species. Supports populations of Tombigbee darter (Etheostoma lachneri), least brook lamprey (Lampetra aepyptera), and bluehead chub (Nocomis leptochephalus)
19	Prairie Pothole, ND	11.0	Currently unknown; likely supports populations of brook stickleback (Culea inconstans) and black bullhead (Ameirus melas)
20	Prairie Lake, ND	30.0	Currently unknown; likely similar to Prairie Pothole lake
21	Arikaree River, CO	2,874.9	Nineteen species, including brassy minnow (Hybognathus hanksinsoni), northern plains killifish (Fundulus kansae), and orangethroat darter
22	South Pond, OK	0.8	No fishes present
23	Pringle Creek, TX	18.1	Currently unknown; likely supports populations of mimic shiner (Notropis volucellus), blackstripe topminnow (Fundulus notatus), and logperch (Percina caprodes)
24	Bozeman Creek, MT	48.7	Currently unknown
25	Blacktail Deer Creek, WY	38.9	Brook trout
26	Fool Creek, CO	2.4	Currently unknown
27	Como Creek, CO	4.8	Greenback cutthroat trout (Oncorhynchus clarki stomias)
28	*Sycamore Creek, AZ*	345.0	Longfin dace (Agosia chrysogaster) and desert sucker (Pantosteus clarki)
29	Red Butte Creek, UT	16.7	Bonneville cutthroat trout (O. clarki utah)
30	East Branch Planting Creek, OR	1.6	Currently unknown; likely supports populations of coastal cutthroat trout (O. clarki clarki)
31	*McRae Creek, OR*	5.2	Coastal cutthroat trout
32	Providence Creek, CA	1.3	No fishes present
33	*Convict Creek, CA*	52.1	Brook trout (Salvelinus fontinalis), brown trout (Salmo trutta), rainbow trout (Oncorhynchus mykiss)
34	Toolik Lake, AK	146.7	At least five species including lake trout (Salvelinus namaycush), Arctic grayling (Thymallus arcticus), and round whitefish (Prosopium cylindraceum)
35	*Oksrukuyik Creek, AK*	73.5	Arctic grayling and slimy sculpin (Cottus cognatus)
36	*Caribou Creek, AK*	30.7	Arctic grayling and slimy sculpin

pled using hand corers. Posted data will specify methodological approaches, and the open-access protocols used to collect the data will allow interested researchers to determine the rationale concerning methodological decisions. Sample collection timing will also be coordinated to maximize data comparability among sites. NEON will identify periods where maximum biological diversity is expected for each target assemblage using externally collected historical data from each domain.

NEON Site Selection Process and Aquatic Sites

Sites in the NEON network are chosen to simultaneously maximize representation among major North American ecosystems and allow researchers to address environmental questions of regional concern. To distribute sites throughout major ecological gradients of North America, NEON used multivariate geographic clustering (Hargrove and Hoffman 1999) to partition the continental United States, Alaska, Hawaii, and Puerto Rico into 20 ecoclimatic domains. All domains (excluding Hawaii) include one to three aquatic sites that fall into two categories: core sites, which will remain fixed in place during the entire 30 years of NEON operations, and relocatable sites, which are intended to move approximately every 5 years to capture variation within a domain and address regional questions of interest. Sites were selected to represent the greatest degree of characteristic ecological attributes of the corresponding domains. Core sites typically consist of ecosystems that are minimally impacted by anthropogenic stressors. Relocatable sites may be in areas impacted by anthropogenic stressors and are usually paired with either core sites or other relocatables to allow contrasting measurements between impacted and relatively intact ecosystems. The data collected from all sites may be used to extrapolate relationships that identify the driving causes of long-term ecological changes to areas not sampled but where partial, extensively sampled, or gridded information is available.

Currently, the candidate aquatic sites in the NEON network include 26 wadable streams, three nonwadable rivers, and seven lakes representing characteristic aquatic ecosystems among a majority of North American ecoregions (Table 1, Figures 3 and 4). Sites are considered as candidates until a land use agreement is obtained. NEON aquatic site selection is informed by external scientific input from those familiar with the respective domain and follows the same criteria of terrestrial and atmospheric site selection: core sites are situated in relatively intact watersheds, whereas relocatable sites may be anthropogenically impacted. Wherever possible, aquatic sites are located adjacent to (i.e., <5 km) NEON tower and terrestrial sites to help couple data among ecosystems. NEON lotic ecosystem sizes range from small, first-order, fishless streams to large rivers that support highly diverse fish communities. The network of sites in Domain 8, the Ozarks Complex, may prove particularly valuable for fisheries and aquatic ecosystem science because they consist of three sites with nested catchments of various sizes within a large river watershed. Domain 8 sites were specifically selected to span the river continuum (Vannote et al. 1980) of the Tombigbee River watershed and include reaches with more than 100 recorded fish species.

The NEON Structure: Current and Future

NEON is an NSF-funded project managed and maintained by an independent, nonprofit corporation (NEON, Inc.) implemented through the Large Facilities Office (LFO). Examples of well-known observatories managed under this program include the Arecibo and Gemini Satellite Observatories. Programs implemented through the LFO typically undergo a multiyear review process with incremental developmental steps prior to operations termed the major research equipment and facilities construction (MREFC) process. Construction funds were awarded in fiscal year 2011; a 5-year construction phase (where sites are fitted with sensors and data collection begins) followed by a 30-year operations phase is now set to ensue. Within each domain, NEON crews stationed in local offices will perform field operations. Central NEON headquarters is located in Boulder, Colorado.

All data will be posted on an open-access, NEON-maintained Internet portal. The portal system will include comprehensive search interfaces, filtering capabilities (e.g., searching within regional and/or date criteria), and decision-support functions to help investigators become fully aware of all available data pertinent to their inquiries. The data acquisition portal is currently under development and many design specifications have yet to be finalized. However, NEON will collaborate with several existing data management initiatives, such as the National Water Quality Monitoring Council and BioOne, to assist with portal development. External researchers will also be consulted to help maximize data portal functionality. Regardless of the final design, an open-source metadata structure and provenance process will ensure that users understand where and how all data are derived. All data will undergo stringent quality assurance/quality control product definition, statistical, and modeling analysis to ensure the identification of erroneous readings. Wherever possible, data will be cross-checked using related sensors or measurements among the NEON data streams. Researchers and the public will be able to access NEON-derived design and protocol documents using the web portal to ensure data comparability and methodological repeatability outside of the observatory. For instance, the standardized, peer-reviewed field protocol applied for fish sampling will be downloadable so that reliably comparable data may be collected elsewhere.

Educational resources and tools are being developed at NEON to ensure that observatory-generated information, including data, is accessible and usable for all interested users. In partnership with stakeholder communities, NEON will employ a variety of approaches to engage communities in the scientific process. Planned educational activities include social media applications, online learning modules, citizen science projects, student research and internship programs, short courses, and workshops to help individuals at all levels of professional development effectively use observatory-generated data. Graduate students from any institution will be able to participate in a competitive field and data analysis course to help familiarize themselves with NEON resources. The NEON web portal will be an interface to many educational resources, including

online learning modules for students hoping to use NEON data. Citizen science programs will enable participants to collect, contribute, interpret, and visualize scientific data that may significantly contribute to scientific inquiry. Project Budburst, the first among such initiatives (comanaged by the Chicago Botanical Garden and NEON), provides an interface for amateur botanists to report the dates of phenological events such as leaf out and senescence at any location. Interested researchers may now access thousands of phenological event data recorded across the country over the past 4 years.

NEON aims to be a dynamic and valued resource by actively encouraging the scientific community to develop research projects that leverage NEON data, facilities, and infrastructure. Currently, the NSF Macrosystems Biology program, supporting research on biological systems at regional to continental scales, is a principal avenue for fostering scientific collaboration with NEON. Other NSF funding programs that have encouraged NEON collaboration to date include the Research Coordination Networks and Campus Cyberinfrastructure–Network Infrastructure and Engineering Program. New collaborative efforts that leverage NEON may also be funded by agencies other than NSF or nongovernmental institutions. Proposals that include the use or leveraging of NEON assets may be submitted by universities, nonprofit institutions, non-academic organizations, or federal agencies. Decisions regarding the use of NEON assets in novel work will be assessed for technical and logistical feasibility by NEON staff in accordance with policies and procedures currently in development and subject to NSF approval. Quantitative, interdisciplinary, and systems-oriented research on biological processes and their interactions with environmental change at continental scales will be particularly encouraged. Smaller scale initiatives, including new technology testing and implemention, will also be possible and promoted through collaborations with NEON scientists. Finally, collaborative research may be fostered through student internships with individuals mentored by both external and NEON scientists.

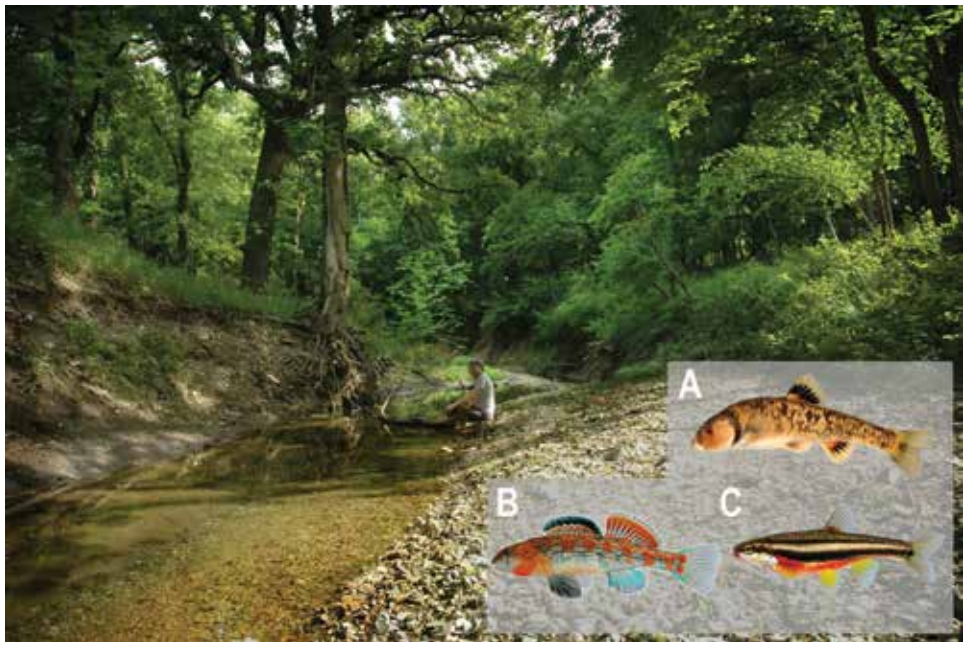


Figure 3. Kings Creek, a NEON candidate core aquatic and STREON site located within the Konza Prairie Biological Station near Manhattan, Kansas. NEON will collect population estimates of fishes, including (A) central stoneroller, (B) orangethroat darter, and (C) southern redbelly dace in Kings Creek for 30 years. Additionally, data from the STREON experiment will allow any interested researcher to explore how populations of these fishes respond to chronic nutrient enrichment and how their extirpation might impact ecological processes in the benthic zone.



Figure 4. Map of NEON North American domains and locations of aquatic sites in the observatory. Site numbers correspond to those listed in Table 1.

Successful analyses and forecasting in fisheries science at broad scales amid pervasive global environmental change will require unprecedented scientific resources. NEON aims to become a transformative tool in the ecological sciences by providing high-quality, nonproprietary, and comprehensive data across spatiotemporal scales beyond the capabilities of individual laboratories. The combined suite of aquatic, terrestrial, and atmospheric data generated by NEON will particularly enhance investigations of material and energy exchanges across apparent ecosystem boundaries, which are increasingly recognized as critically important in aquatic ecosystems (Lamberti et al.

2010). To learn more about NEON, including the observatory structure, data products, working group members, and construction updates, please visit the NEON website (neoninc.org).

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STUDENT ANGLE

SIUC Subunit Blends Research and Service in Pursuit of Professional Development

Carlin Fenn, Jeffrey Hillis, and Jesse Trushenski

Center for Fisheries, Aquaculture and Aquatic Sciences, Southern Illinois University Carbondale, Carbondale, IL 62901.

Members of the Southern Illinois University Carbondale (SIUC) Subunit of the Illinois Chapter of the American Fisheries Society take a multi-faceted approach to promote the conservation of aquatic resources through personal, professional, and community development. From teaching youths about aquatic ecology and fish identification, to the development of the inaugural "Carp-A-Thon" for area anglers, the SIUC IL-AFS Subunit serves as an important community resource. This past year alone, members planned and participated in well over a dozen fisheries-related outreach events, including the Illinois Department of Natural Resources' Urban Fishing program, where members had the chance to introduce youngsters to the joys of angling and the importance and value of the great outdoors.

Opportunities abound for Subunit members to develop their fisheries and interpersonal skills by electrofishing area lakes, generating stock assessment reports, and presenting their findings to anglers and members of the community. This year, members experienced a unique opportunity to culture freshwater prawn as part of an SIUC-sponsored research project. At the end of the summer, the tasty crustaceans were harvested and sold to students and faculty of SIUC and greater Southern Illinois community as a fundraiser for the Subunit. Additionally, members gained pond-culture experience, learned about prawn biology, and collected data for a bioenergetics study.

The next few months are an exciting time for the SIUC IL-AFS Subunit, as members are currently developing monthly workshops to give new students out-of-the-classroom learning opportunities in electrofishing, lab and culture techniques, pond management, and boat maintenance, safety, and operation. These opportunities build professional skill sets, human and resource networks, and a sense of camaraderie among both new and old members of the fisheries community at SIUC. The SIUC Subunit also serves as an important means of mentoring undergraduate students by incorporating real field and lab experiences to supplement traditional classroom-style learning. Graduate students benefit from undergraduate assistance that is always available. This relationship is important to the growth of the program and describes the Subunit's mission. Encouraging academic excellence, robust research productivity, and community service are the focus of the SIUC IL-AFS Subunit. In addition to serving locally, the Subunit also has a history of helping the Illinois Chapter and AFS Sections at various levels. Through the Subunit, members feel a connection to our local cadre of fish-heads, as well as AFS and the broader fisheries community.

To learn more about the SIUC IL-AFS Subunit, please visit their website at http://fishstudent.rso.siu.edu. For more information on establishing a Student Subunit at your college or university, contact your state AFS Chapter.







(Left): SIUC IL-AFS member Jake Norman instructs beginning anglers on how to properly cast a rod and reel during the 2012 Illinois Department of Natural Resources' Urban Fishing program. Through this vital community resource, many children had the opportunity to catch their first fish, thus generating a newfound enthusiasm for fishing within the youngest members of the Southern Illinois community. (Center): From May through September 2012, SIUC IL-AFS members cultured freshwater prawn in SIUC-provided ponds. Members harvested the prawn in late September, and sold them by the pound as a fundraiser for the Subunit. Not only did Subunit members witness how tasty freshwater prawn are, but they also gained experience on data collection for a bioenergetics study and learned about prawn biology and pond culture techniques. Above, SIUC IL-AFS member and prawn fundraiser organizer Bonnie Mulligan holds a "blue claw" male prawn during the harvest. (Right): SIUC IL-AFS member and past-president John Bowzer holds a contestant's carp entry for the 1st annual Southern Illinois "Carp-A-Thon". The fishing tournament was sponsored in part by the SIUC IL-AFS, and served as both a platform to both raise awareness of the Bighead and Silver carp infiltration of local waterways and a fundraiser for the Subunit. Prizes were awarded to the anglers for "Biggest Carp" and "Top Ten Heaviest Fish."



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The **American Fisheries Society Student Writing Contest** recognizes students for excellence in the communication of fisheries research to the general public.

Undergraduate and graduate students are encouraged to submit a 500- to 700-word article explaining their own research or a research project in their lab or school. The article must be written in language understandable to the general public (i.e., journalistic style). The winning article will be published in ***Fisheries.***

Students may write about research that has been completed, is in progress, or is in the planning stages. The papers will be judged according to their quality and their ability to turn a scientific research topic into a paper for the general public and will be scored based upon a grading rubric. Check the AFS Web site (www.fisheries. org) awards page for the grading rubric.

American Fisheries Society Adopts New Policy, Encourages Efforts to Understand and Limit Effects of Lead in Sport Fishing Tackle on Fish and Wildlife

Jesse Trushenski and Paul Radomski

American Fisheries Society, Resource Policy Committee

In October of 2012, the American Fisheries Society (AFS) voted to adopt a new policy statement on "Lead in Sport Fishing Tackle." Like all AFS policies, this document represents the collective voice of the oldest, largest, and most influential professional organization dedicated to the fisheries sciences. The new policy draws attention to the negative effects of lead in the environment and encourages scientists, regulatory authorities, tackle manufacturers, the sport fishing community, and other stakeholders to work together to understand and limit any negative effects of lead-based tackle (e.g., sinkers, jigs) on fish and other organisms.

Lead is a naturally occurring but toxic element. Because of its negative effects on human and animal health, lead is banned in products such as gasoline, paint, and solder in many countries. However, lead is still commonly used in fishing tackle because it is readily available, dense, malleable, and inexpensive. Though lost fishing tackle can remain intact and relatively stable for decades or centuries in aquatic systems, if ingested by animals, the lead in these products becomes more biologically available and can result in lethal exposures. The effects of ingesting such tackle were established in waterbirds in the 1970s and 1980s, following lead poisoning events in localized populations of loons and swans. Although population-level effects have not been unequivocally demonstrated and lost tackle represents a relatively small fraction of the total amount of lead found in the environment (surface runoff, atmospheric deposition, and mining activities are more significant sources), given the likelihood of ingestion and the magnitude of organism-level effects of exposure following ingestion, it would seem prudent to assess, understand, and limit the negative effects of lead in sportfishing tackle on fish and other aquatic organisms.

This issue was reviewed by members of the AFS Resource Policy Committee (RPC), under the principal leadership of Paul Radomski, Tom Bigford, and Jesse Trushenski. In cooperation with a special committee established by then AFS President Wayne Hubert, Radomski and the other members of the RPC prepared a draft policy statement. Following review by the AFS RPC, governing board, and membership at large, the Society adopted the policy, calling for stakeholders to address the potential effects of lead in sportfishing tackle on fish populations.

Accordingly, the policy of the AFS, in regard to lead in sport fishing tackle, is to

1. Recognize that lead has been known for centuries to be toxic to biological organisms. Thus, the loss and subsequent ingestion of lead sinkers and jigheads by aquatic animals and the potential ramifications of lead ingestion is a natural resource management issue.
2. Understand that the impact of ingested lead on individuals of certain waterfowl species is generally accepted, but population-level impacts on fish and wildlife species are not well documented. Although conclusive scientific proof of these effects is not currently available, actions to inform, educate, and encourage sportfishing tackle manufacturers, users, and researchers to reduce future introductions of lead into aquatic ecosystems appears advisable. Accordingly, collaborate with fish and wildlife professionals, tackle manufacturers, anglers, policy makers. and the public to encourage the use of non-lead forms of small fishing sinkers and jigheads that are protective of potentially affected fish and wildlife populations.
3. Encourage scientifically rigorous research on lead tackle aimed at generating toxicological and environmental chemistry data including bioavailability assessments; support monitoring and modeling of exposure and effects on at-risk populations; encourage studies predicting consequences of exposure and long-term population-level effects of different tackle material; and encourage studies on reducing the economic and social barriers to nontoxic fishing tackle development and use.
4. Recognize that the hunting and angling communities can be important advocates and forces of change regarding natural resources issues and support educational efforts to promote greater public awareness and understanding of the consequences of lead exposure in wildlife species and the potential gains in environmental quality from use of lead-free fishing tackle.
5. Update policy language as focused research provides additional data on lead tackle-related impacts.

To read the full text of the new policy statement or any of the society's current policies, please visit the American Fisheries Society online at http://fisheries.org/policy_statements.

MISSION STATEMENT

Fisheries is the monthly peer-reviewed membership publication of the American Fisheries Society (AFS). Its goal is to provide timely, useful, and accurate information on fisheries science, management, and the fisheries profession for AFS members. Some types of articles which are suitable for *Fisheries* include fishery case histories, review or synthesis articles covering a specific issue, policy articles, perspective or opinion pieces, essays, teaching case studies, and current events or news features. We particularly encourage the submission of short-form (under 5 typeset pages) "mini-review" articles. Our goal is to move towards four science-based papers in each issue. We will waive page charges for even shorter articles (under 2 typeset pages) on such articles as current events in fisheries science, interviews with fisheries scientists, history pieces, informative how-to articles, etc. We also encourage articles that will expose our members to new or different fields, and that recognize the varied interests of our readers. Research articles may be considered if the work has broad implications or applications and the subject matter can be readily understood by professionals of a variety of backgrounds. *Fisheries* is the Society's flagship publication and is the mostly widely read fisheries science publication in the world. Accordingly, content submitted for consideration should appeal broadly to fisheries professionals and speak to the interests of the AFS membership. Lengthy, highly technical, or narrowly focused research articles are better suited to the AFS technical publications, and we encourage authors to consider the other AFS journals as venues for these works.

REVIEWED ARTICLES

***IMPORTANT**

The maximum length of articles accepted in *Fisheries* is 10 typeset pages (including photos, figures, tables, pull quotes, titles, translations, etc.). One full page of article text with absolutely no figures, tables, pull quotes, titles, headers, translations, or photos is approximately 880 words or 6100 characters including spaces. Please adhere to this standard, taking figures and other non-text content into consideration, when preparing manuscripts for submission to *Fisheries*.

Features, Perspectives, and Review Articles

We encourage submission of topical manuscripts of broad interest to our readership that address contemporary issues and problems in all aspects of fisheries science, management, and policy. Articles on fisheries ecology and aquatic resource management; biology of fishes, including physiology, culture, genetics, disease, and others; economics and social issues; educational/administrative concepts, controversies, techniques, philosophies, and developments; and other general interest, fisheries-oriented subjects will be considered. Policy and issue papers are welcome, particularly those focusing on current topics in fisheries policy. As noted above, we are particularly interested in mini-reviews, which should concisely but comprehensively summarize a topic under 5 typeset pages or less. Papers are judged on scientific and professional merit, relevance, and interest to fisheries professionals. Features and perspectives generally should not exceed 4,500 words (excluding references and tables) and should not cite more than 40 references. Please consult the managing editor PRIOR to submission for a length or reference limit exemption for review articles or articles of Society-wide significance.

Please submit your manuscript online using our manuscript tracking website at http://mc.manuscriptcentral.com/fisheries. If you cannot submit your manuscript online, please e-mail or phone the managing editor, Sarah Fox, for instructions: sgilbertfox@fisheries.org or 301-897-8616 x220 (for fastest response, please e-mail).

Essays

Essays are thought-provoking or opinion articles based upon sound science. Essays may cover a wide range of topics, including professional, conservation, research, AFS, political, management, and other issues. Essays may be submitted in conjunction with a full feature article on the same topic. Essays can be up to 2,000 words, may include photographs or illustrations, and should not cite more than eight references. However, essays should provide scientific documentation, unlike unreviewed opinion pieces (below). Essays are peer-reviewed based on the following criteria: contribution to the ongoing debate, logical opinion based on good science, persuasiveness, and clarity of writing. Reviewer agreement with the opinion of the views expressed is not a criterion. Essays do not have page charges or abstracts. Essays should be formatted and submitted online as described above.

Fisheries Education

Fisheries will consider publication of case studies and other articles specifically intended as teaching tools. These articles, including case studies or short topical summaries, should be formatted to be used for teaching aids for courses taught at the undergraduate level. Fisheries Education articles should be readily understood by undergraduate students with basic training in biological/ecological sciences, and include background information, discussion questions, teaching notes, and references. Peer review of teaching case studies and educational topics will be handled by a special committee of the AFS Education Section.

Materials to Submit

- Assemble manuscripts in this order: title page, abstract page, text, references, tables, figure captions. Tables may be included at the end of the article file or may be submitted as separate files. Figures should not be embedded in the article file and should be submitted separately.
- Authors are strongly encouraged to submit a word processing file in either Word or plain text format.
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General Instructions

- Consult current issues for additional guidance on format.
- Manuscripts should be double-spaced, including tables, references, and figure captions.

- Leave at least a 1-in margin on all sides. Indent all paragraphs. Number pages sequentially and use continuous line numbering,
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UNREVIEWED ARTICLES

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AFS members are encouraged to submit items for the Unit News, Member Happenings, Obituaries, Letters to the Editor, and Calendar departments. Dated material (calls for papers, meeting announcements, and nominations for awards) should be submitted as early as possible, but at least eight weeks before the requested month of publication. AFS Unit News and Letters should be kept under 400 words and may be edited for length or content. Obituaries for former or current AFS members may be up to 600 words long and a photo of the subject is welcome. Do NOT use the online manuscript tracking system to submit these items—the text and 300 dpi digital photos (TIF or JPG) for all departments except the Calendar should be e-mailed to the managing editor at sgilbertfox@fisheries.org, or mailed to the address below.

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For information about submitting a Students' Angle column, please contact Student Subsection President Jeff Fore at jdfore@mizzou.edu.

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The Four Fs of Fish: Communicating the Public Value of Fish and Fisheries

Abigail J. Lynch and William W. Taylor

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"Fish? Why fish?!" This is a common question we are often asked by those outside our field upon learning our profession. They are curious as to why we devote our lives to the study, conservation, restoration, and propagation of fish and associated habitats. This question can come anywhere and at any time. Though it is a common inquiry, do we, as professionals and as a profession, have a good answer?

Effectively demonstrating the value of fish and the fisheries supply chain they create is as important for the future of our own profession as for the fish. This, however, is no easy task. The average American eats approximately 15.8 pounds of fish and shellfish per year (NOAA 2010) and less than 14% of adult Americans report that they participate in recreational fishing (USFWS 2012). So, in general, Americans have little to no direct interaction with fish. In spite of this, our role as fisheries professionals is to clearly articulate to the public and policy makers that fish are important and have value – locally, regionally, nationally, and internationally. Such demonstration of public value ensures that fish and fisheries are afforded appropriate consideration in decision making – from the dinner table to the United Nations general assembly floor. Fish are important; no, they are more than important. They are essential to the survival of mankind. Fish, after all, directly or indirectly contribute to subsistence, livelihoods, health, and prosperity for much of the world.

As fisheries professionals, we are all passionate about fish. This personal and professional passion emanates for many different reasons, as shown by the diversity of the American Fisheries Society sections and membership. However, our drive is often hard to explain to someone who doesn't share the same interest and wonder for fish, their habitats, and fisheries.

We [*the authors*] propose "The Four Fs of Fish": Food, Finances, Fun, and Function as a means to effectively communicate the public value of fish and fisheries. Surely, there are other values, but these four can start the discussion and hone our passion into something tangible to the public and policy makers.

FOOD

Perhaps the most direct argument to make in support of the importance of fish and their habitats is food. Capture fisheries are the last large-scale wild food resource in the world and aquaculture is a quickly growing sector. Both provide essential protein and nutrients to many across the globe. Fish directly provide more than 1.5 billion people with almost 20% of their animal protein and another 3.0 billion with at least 15% (FAO 2010). This equates to more than 40% of the world's human population.

Fish are also an important indirect source of protein for many others who generally do not realize it. Approximately 12.4% of global fishery production is reduced to fish meal and fish oil (FAO 2009), which is subsequently formulated into specialized feed for livestock and aquaculture operations. So, choosing between chicken and fish as meal options may, in fact, be choosing fish or reprocessed fish. We can do a better job of emphasizing the role of fish in other protein sources. For example, instead of asking "how's the chicken?" to someone enjoying a piece of fried chicken, ask "how's the fish?" By helping people understand the supply chain that leads to their meals, we will help them appreciate the importance of fish as a food source that provides healthy, nutritious meals for many at local and global scales.

FINANCES

People recognize the importance of economic impact or, as the old adage goes, money talks and employment walks. First-sale value of global capture fisheries production and aquaculture is approximately US$93.9 billion and US$98.4 billion, respectively, and US$192.3 billion, collectively (FAO 2010). Numbers that large can seem intangible, but the first-sale of value of fisheries basically equates to one-seventh of the U.S. Gross Domestic Product.

More than strict monetary value, fisheries are significant sources of employment, income, and livelihood. Globally, 44.9 million people are directly engaged in capture fisheries or in aquaculture (FAO 2010). So, fisheries employ over 20 times more people than Walmart, the world's largest private employer. Taking families and dependents into account, fisheries are an important source of income and livelihood for 8% of the world's population, around 540 million people (FAO 2010). And, these are just minimum estimates. These Food and Agriculture Organization of the United Nations (FAO) statistics are very likely a gross underestimate of their full value because obtaining accurate capture and employment statistics on small-scale fisheries, the bulk of the world's fisheries, is difficult as they are highly dispersed and underreported (Cochrane et al. 2011).

FUN

Fish, lest we forget, also provide fun. Recreational fishers, snorkelers, SCUBA divers, and hobby aquarists seek enjoyment and relaxation through interacting with fish and their habitats. Though we cannot over-emphasize the value of these experiences to the individuals who find fish fun, the financial value

of recreation can be understood even by those choosing not to engage in these types of activities. In 2011, for example, American anglers spent $41.8 billion in support of fishing activities (e.g., trips, equipment, licenses; USFWS 2012). Even those who have never picked up a fishing rod or visited an aquarium can appreciate the employment and economic stimulus generated by recreational fishing and fish watching.

Fish are important components of most human systems. While some cultural values, like recreation and tourism, can be translated into economic impact, other religious, spiritual, or artistic values are more difficult to assess economically. Nonetheless, fish are symbolized in every major world religion and the natural beauty of aquatic ecosystems is commonly evoked in art.

FUNCTION

Without question, fishes are the most diverse, numerous group of vertebrates on the planet. The estimated 27,977 species of fishes make up more than half of the approximate 54,711 recognized living vertebrate species (Nelson 2006) and occupy almost all major aquatic habitats (Helfman et al. 2009). In this role, fishes are a particularly important taxa for biodiversity conservation and resilience of ecosystems to change (Naeem 2012). As such, they often serve as symbols of the health and integrity of their habitats. They are, for all practical purposes, the aquatic version of "canaries in a coal mine." Fish are critical links in aquatic systems – indicators of ecosystem health and a litmus test of what the potential impacts could be for humans.

For people who fish, eat fish, or recreate in aquatic environments, the value of fish and fisheries is an easy sell. They use and appreciate the resource and want to ensure that fish will be around for them and future generations to use. But, demonstrating the value of fish to those who have no direct contact with them can be daunting, especially when negotiating tradeoffs for water security, agriculture, power generation, and other sectoral interests. As a whole, we, as professionals can be better communicators. We need to be cognizant that others may not share our passion for fish and we must provide them with a clear rationale of why fish and their habitats should be important to them: Food, Finances, Fun, and Function. Our future and that of fishes depend on us to do just that – make fish meaningful and important to all!

Fast Stats

Food
- 3.0 billion people (>40% of global population) depend directly on fish as an important source of protein.

Finances
- 540 million people (8% of global population) depend upon fishery industries for livelihood and income.

Fun
- Anglers in the United States spend over $40 billion in support of fishing activities annually.

Function
- Fishes comprise more than half of all vertebrate species and occupy all major aquatic habitats.

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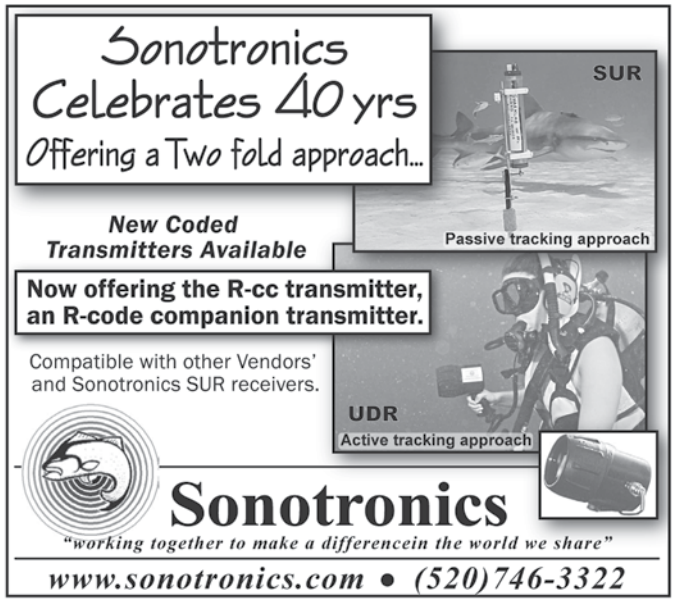
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JOURNAL HIGHLIGHTS

North American Journal of Fisheries Management, Volume 32, Number 6, December 2012



[Management Brief] A Prototype Splitter Apparatus for Dividing Large Catches of Small Fish. *Martin A. Stapanian and William H. Edwards. 32: 1033–1038.*

Largemouth Bass Predation Effect on Stocked Walleye Survival in Illinois Impoundments. *Jonathan A. Freedman, R. John H. Hoxmeier, Lisa M. Einfalt, Ronald C. Brooks, and David H. Wahl. 32: 1039–1045.*

Habitat Associations of Fish Species of Greatest Conservation Need at Multiple Spatial Scales in Wadeable Iowa Streams. *Anthony R. Sindt, Michael C. Quist, and Clay L. Pierce. 32: 1046–1061.*

[Management Brief] The Potential for Vessel Interactions with Adult Atlantic Sturgeon in the James River, Virginia. *Matthew T. Balazik, Kevin J. Reine, Albert J. Spells, Charles A. Fredrickson, Michael L. Fine, Greg C. Garman, and Stephen P. McIninch. 32: 1062–1069.*

Elevated Streamflows Increase Dam Passage by Juvenile Coho Salmon during Winter: Implications of Climate Change in the Pacific Northwest. *Tobias J. Kock, Theresa L. Liedtke, Dennis W. Rondorf, John D. Serl, Mike Kohn, and Karin A. Bumbaco. 32: 1070–1079.*

Do Anglers Know What They Catch? Identification Accuracy and Its Effect on Angler Survey-Derived Catch Estimates. *Kevin S. Page, Richard D. Zweifel, George Carter, Nick Radabaugh, Michael Wilkerson, Matthew Wolfe, Michael Greenlee, and Kipp Brown. 32: 1080–1089.*

Effect of Survey Design and Catch Rate Estimation on Total Catch Estimates in Chinook Salmon Fisheries. *Joshua L. McCormick, Michael C. Quist, and Daniel J. Schill. 32: 1090–1101.*

Empirical Standard Weight Equation for the Aegean Chub Squalius fellowesii, an Endemic Freshwater Fish Species of Western Anatolia, Turkey. *Daniela Giannetto, Laura Pompei, Massimo Lorenzoni, and Ali Serhan Tarkan. 32: 1102–1107.*

Precision of Channel Catfish Catch Estimates Using Hoop Nets in Larger Oklahoma Reservoirs. *David R. Stewart and James M. Long. 32: 1108–1112.*

Improving Size Selectivity of Shrimp Trawls in the Gulf of Maine with a Modified Dual-Grid Size-Sorting System. *Pingguo He and Vincent Balzano. 32: 1113–1122.*

Incorporating Movement Patterns to Improve Survival Estimates for Juvenile Bull Trout. *Tracy Bowerman and Phaedra Budy. 32: 1123–1136.*

Performance of Surplus Production Models with Time-Varying Parameters for Assessing Multispecies Assemblages. *Geneviève M. Nesslage and Michael J. Wilberg. 32: 1137–1145.*

Influence of Environmental Variables and Species Interactions on Sport Fish Communities in Small Missouri Impoundments. *Paul H. Michaletz, Daniel V. Obrecht, and John R. Jones. 32: 1146–1159.*

[Management Brief] Sampling Glacial Lake Littoral Fish Assemblages with Four Gears. *Daniel J. Dembkowski, Melissa R. Wuellner, and David W. Willis. 32: 1160–1166.*

Impacts of Highway Construction on Redd Counts of Stream-Dwelling Brook Trout. *Marc Pépino, Jan Franssen, Marco A. Rodríguez, and Pierre Magnan. 32: 1167–1174.*

[Management Brief] Latitudinal Influence on Age Estimates Derived from Scales and Otoliths for Bluegills. *Lucas K. Kowalewski, Alexis P. Maple, Mark A. Pegg, and Kevin L. Pope. 32: 1175–1179.*

Privately Owned Small Impoundments in Central Alabama: A Survey and Evaluation of Management Techniques for Largemouth Bass and Bluegill. *Norman V. Haley III, Russell A. Wright, Dennis R. DeVries, and Micheal S. Allen. 32: 1180–1190.*

Frequency of Strong Year-Classes: Implications on Fishery Dynamics for Three Life History Strategies of Fishes. *Daniel J. Daugherty and Nathan G. Smith. 32: 1191–1200.*

[Management Brief] Sex at Length of Summer Flounder Landed in the New Jersey Recreational Party Boat Fishery. *Jason M. Morson, Eleanor A. Bochenek, Eric N. Powell, and Jennifer E. Gius. 32: 1201–1210.*

A Comparative and Experimental Evaluation of Performance of Stocked Diploid and Triploid Brook Trout. *Phaedra Budy, Gary P. Thiede, Andrew Dean, Devin Olsen, and Gilbert Rowley. 32: 1211–1224.*

Inferring Adult Status and Trends from Juvenile Density Data for Atlantic Salmon. *Heather D. Bowlby and A. Jamie F. Gibson. 32: 1225–1236.*

Assessing Avian Predation on Juvenile Salmonids using Passive Integrated Transponder Tag Recoveries and Mark–Recapture Methods. *Danielle Frechette, Ann-Marie K. Osterback, Sean A. Hayes, Morgan H. Bond, Jonathan W. Moore, Scott A. Shaffer, and James T. Harvey. 32: 1237–1250.*

Strategies to Control a Common Carp Population by Pulsed Commercial Harvest. *Michael E. Colvin, Clay L. Pierce, Timothy W. Stewart, and Scott E. Grummer. 32: 1251–1264.*

Expanding Aerial–Roving Surveys to Include Counts of Shore-Based Recreational Fishers from Remotely Operated Cameras: Benefits, Limitations, and Cost Effectiveness. *C. B. Smallwood, K. H. Pollock, B. S. Wise, N. G. Hall, and D. J. Gaughan. 32: 1265–1276.*

Continued from page 3

registration fees to compensate the instructor and pay for the technology required to deliver the course effectively and add some funds to the AFS coffers.

No doubt, what I have prescribed for the Special Committee on Educational Requirements and the Continuing Education Committee is a lot of work for a set of volunteers and will likely take several years to accomplish. The tasks should probably become a matter of routine for the AFS, undertaken every 5–10 years to ensure that students and career professionals being trained in fisheries-related disciplines have the right educational foundation for meeting the challenges that lie ahead.

STUDENT FUNDING AVAILABLE

American Institute of Fishery Research Biologists (AIFRB)

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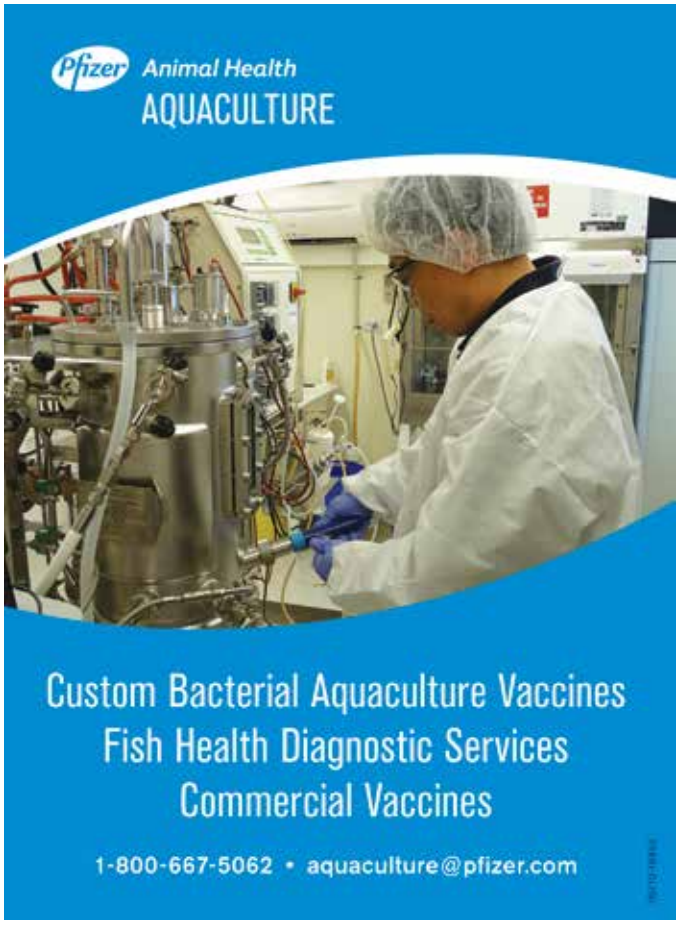
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Fisheries Events

To submit upcoming events for inclusion on the AFS web site calendar, send event name, dates, city, state/province, web address, and contact information to sgilbertfox@fisheries.org.

(If space is available, events will also be printed in Fisheries magazine.)

More events listed at www.fisheries.org

DATE	EVENT	LOCATION	WEBSITE
February 5–7, 2013	32nd International Kokanee Workshop	Fort Collins, CO	Jesse Lepak at Jesse.Lepak@state.co.us
February 7–8, 2013	Winter Fisheries Training for Acoustic Tag & Hydroacoustic Assessments	Seattle, WA	www.HTIsonar.com/at_short_course.htm
February 14–15, 2013	Using Hydroacoustics for Fisheries Assessment		www.HTIsonar.com/at_short_course.htm
February 21–25, 2013	Fish Culture Section Mid-Year Business Meeting	Nashville, TN	www.was.org/WasMeetings/meetings/Default.aspx?code=AQ2013
February 21–25, 2013	Aquaculture 2013	Nashville, TN	www.was.org/WasMeetings/meetings/Default.aspx?code=AQ2013
March 13–16, 2013	31st Annual Salmonid Restoration Conference	Fortuna, CA	http://www.calsalmon.org/salmonid-restoration-conference/31st-annual-salmonid-restoration-conference
March 26–29, 2013	Responses of Arctic Marine Ecosystems to Climate Change Symposium	Anchorage, AK	seagrant.uaf.edu/conferences/2013/wakefield-arctic-ecosystems/index.php
April 8–12, 2013	7th International Fisheries Observer and Monitoring Conference (7th IFOMC)	Viña del Mar, Chile	www.ifomc.com/
April 15–18, 2013	Western Division of the AFS Annual Meeting	Boise, ID	www.idahoafs.org/meeting.php
April 25–26, 2013	NPAFC 3rd International Workshop on Migration and Survival Mechanisms of Juvenile Salmon and Steelhead in Ocean Ecosystems	Honolulu, HI	http://www.npafc.org/new/index.html
June 24–28, 2013	9th Indo-Pacific Fish Conference	Okinawa, Japan	http://www.fish-isj.jp/9ipfc
July 14–20, 2013	2nd International Conference on Fish Telemetry	Grahamstown, South Africa	Contact: Dr. Paul Cowley at tagfish@gmail.com
August 3–7, 2014	International Congress on the Biology of Fish	Edinburgh, United Kingdom	http://icbf2014.sls.hw.ac.uk

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Employers: to list a job opening on the AFS online job center submit a position description, job title, agency/company, city, state, responsibilities, qualifications, salary, closing date, and contact information (maximum 150 words) to jobs@fisheries.org. Online job announcements will be billed at $350 for 150 word increments. Please send billing information. Listings are free (150 words or less) for organizations with associate, official, and sustaining memberships, and for individual members, who are faculty members, hiring graduate assistants. if space is available, jobs may also be printed in *Fisheries* magazine, free of additional charge.

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The American Fisheries Society (AFS) seeks a scientist with a broad perspective on fisheries to serve as editor of North American Journal of Fisheries Management (NAJFM). Editor must be committed to fast-paced deadlines, and would be appointed for a five-year renewable term which begins January 2013.

Duties include:

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3. Setting editorial standards for NAJFM in keeping with the objectives of the publication in accordance with AFS policies, and guidance provided by the Publications Overview Committee and the NAJFM editorial board;

4. Making recommendations to enhance the vitality and prestige of the Journal.

Qualifications: This position requires marine and estuarine fisheries expertise.

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Email: alerner@fisheries.org

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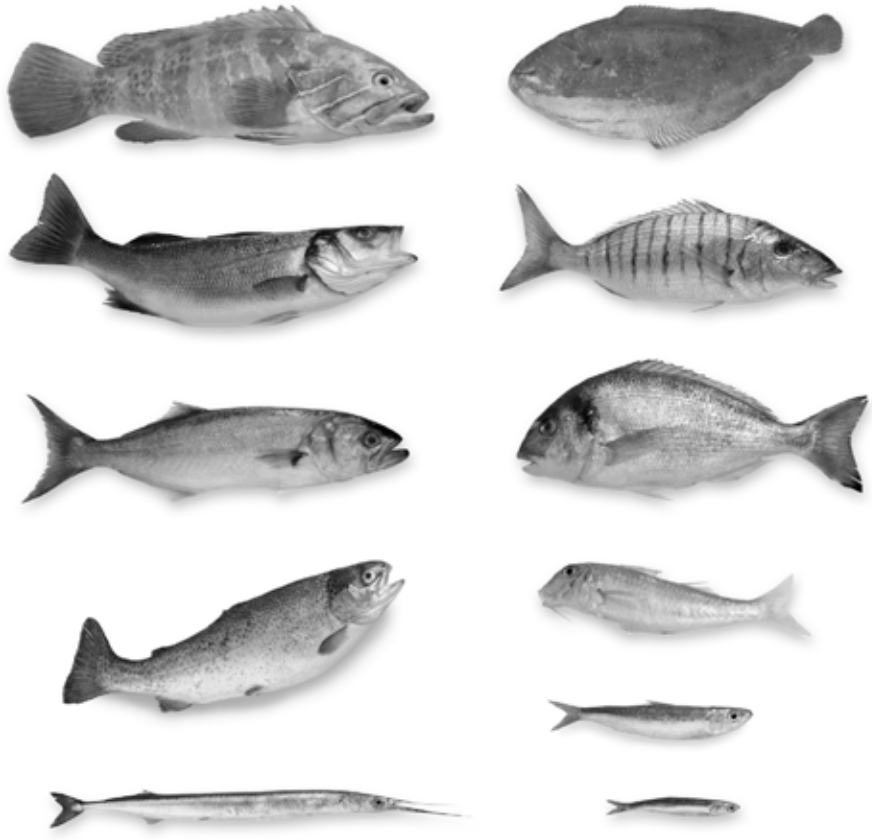
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Contact: To Apply: For more information see the WDFW Employment Page for a complete listing at. This will explain job duties, minimum qualifications, competencies and desirable qualifications. If you have questions about this recruitment, you may contact Margaret Gordon, Recruitment Specialist at 360 902-2209.

Link: http://wdfw.wa.gov/employment/index.htm

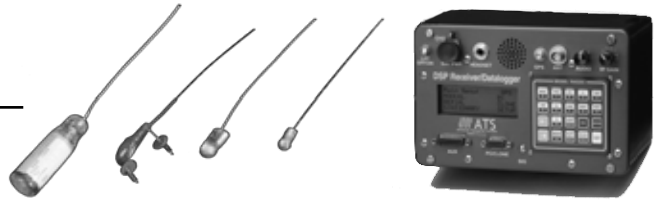
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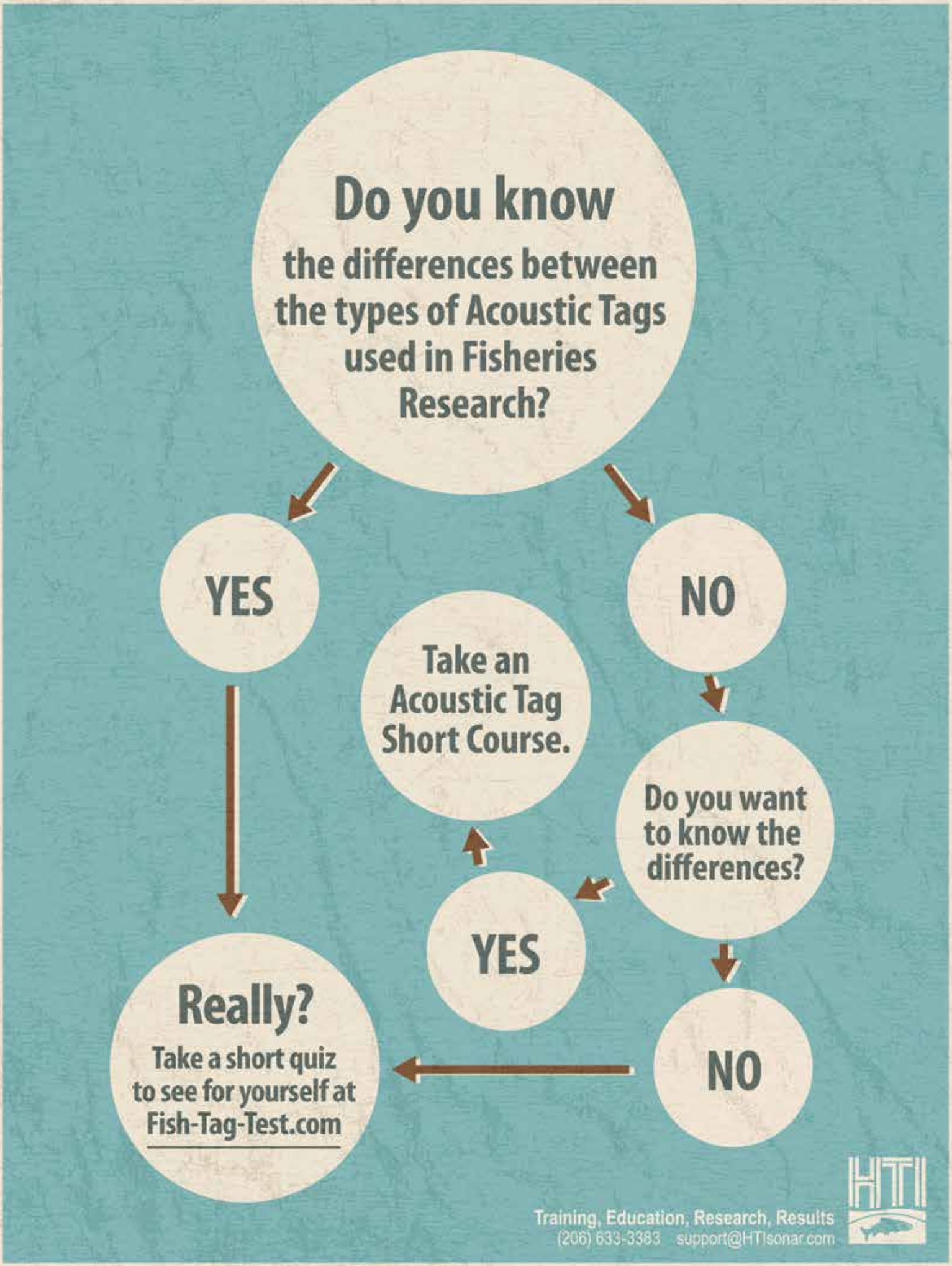
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June 29, 2011

Office of Groundwater and Drinking Water
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels

Dear Sir or Madam:

Thank you for the opportunity to provide comments on the Environmental Protection Agency's ("EPA") development of UIC Class II permitting guidance for hydraulic fracturing activities that use diesel fuels in fracturing fluids.

The Natural Resources Defense Council ("NRDC") is a national, non-profit legal and scientific organization with 1.3 million members and activists worldwide. Since its founding in 1970, NRDC has been active on a wide range of environmental issues, including fossil fuel extraction and drinking water protection. NRDC is actively engaged in issues surrounding oil and gas development and hydraulic fracturing, particularly in the Rocky Mountain West and Marcellus Shale regions.

Earthjustice is a non-profit public interest law firm originally founded in 1971. Earthjustice works to protect natural resources and the environment, and to defend the right of all people to a healthy environment. Earthjustice is actively addressing threats to air, water, public health and wildlife from oil and gas development and hydraulic fracturing in the Marcellus Shale and Rocky Mountain regions.

Founded in 1892, the Sierra Club works to protect communities, wild places, and the planet itself. With 1.4 million members and activists worldwide, the Club works to provide healthy communities in which to live, smart energy solutions to combat global warming, and an enduring legacy of for America's wild places. The Sierra club is actively addressing the environmental threats to our land, water, air from natural gas extraction across the United States.

General Comments

We appreciate EPA's decision to issue permitting guidance for hydraulic fracturing using diesel fuel. While this practice is regulated under the currently existing UIC Class II regulations, hydraulic fracturing also poses unique risks to USDWs. For that reason, we believe that EPA must promulgate new regulations in addition to permitting guidance. The issuance of permitting guidance under Class II is an important stopgap, but only through regulation that specifically address hydraulic fracturing using diesel can USDWs be adequately protected.

UNPERMITTED INJECTION OF DIESEL FUELS THROUGH HYDRAULIC FRACTURING IS A VIOLATION OF THE SAFE DRINKING WATER ACT

As an initial matter, EPA should use its proposed guidance to reemphasize an important point: the use of diesel fuel injection for hydraulic fracturing is already subject to the requirements of the Safe Drinking Water Act ("SDWA"), whether or not it is specifically addressed by EPA guidance or state UIC programs.

The statutory definition of "underground injection" as "the subsurface emplacement of fluids by well injection" plainly encompasses hydraulic fracturing. 42 U.S.C. § 300h(d)(1); see, e.g., Legal Environmental Assistance Found. v. EPA, 118 F.3d 1467, 1475 (11th Cir. 1997) (holding that the statute requires EPA to regulate hydraulic fracturing operations). SDWA underscores this point by excluding hydraulic fracturing from the definition of "underground injection," except where diesel fuel is used. 42 U.S.C. § 300h(d)(1)(B)(ii). Such an exclusion would be unnecessary if hydraulic fracturing were not otherwise a form of SDWA-regulated underground injection.

Because it represents a form of underground injection, all hydraulic fracturing with diesel fuel violates SDWA unless a permit has been issued. 42 U.S.C. § 300h(b)(1)(A); 40 C.F.R. §§ 144.1(d)(6), (g), 144.11.

Because diesel fuel contains carcinogenic benzene, toluene, ethylene, and xlyene ("BTEX") compounds it poses a major concern.[1] Therefore, when Congress exempted some hydraulic fracturing injections from the Act, it explicitly limited that exemption to wells where fluids "other than diesel fuels" are used. 42 U.S.C. § 300h(d)(1)(B)(ii).[2] For those hydraulic fracturing injections using diesel fuel, the SDWA Class II well program applies. See 40 C.F.R. § 144.6(b).

Nevertheless, many companies have continued to use diesel fuel without obtaining a permit. The minority staff of the House Committee on Energy and Commerce determined that between 2005 and 2009 "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[3] The investigators determined that "no oil and gas service companies have sought – and no state and federal regulators have issued – permits for diesel fuel use in hydraulic fracturing."[4]

In light of this noncompliance (and assertions of confusion on the part of hydraulic fracturing service companies), EPA should reaffirm that these injections were illegal, and future injections without a permit are also illegal.

EPA should further clarify that these injections were barred under SDWA whether or not they occurred in a state with primacy to enforce SDWA, and whether or not such states had rules on the books. This is so because the SDWA requires each state to prohibit unpermitted injections. 42 U.S.C. § 300h(b)(1)(A).

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[1] For example, EPA described diesel as the "additive of greatest concern" in hydraulic fracturing operations.US EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) at ES-12.

[2] Of course, "[n]otwithstanding any other provision of [the SDWA]," including the hydraulic fracturing exemption, EPA retains its power to act against injection practices which "may present an imminent and substantial endangerment to the health of persons." 42 U.S.C. § 300i(a). EPA could also use this authority to address diesel injection.

[3] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2001) at 1.

[4] *Id.*; *see also* Dusty Horwitt, Environmental Working Group, *Drilling Around the Law* (2009) at 12-13 (documenting state and federal agency officials' failure to regulate these injections).

The statute leaves no room for states to simply ignore illegal injections to which the Act applies. Moreover, the SDWA regulations provide that each state program "must be administered in accordance" with various federal regulations, including 40 C.F.R. § 144.11, which prohibits "[a]ny underground injection, except into a well authorized by rule or except as authorized by permit." 40 C.F.R. § 145.11(a)(5). Thus, even if a state's rules do not explicitly address hydraulic fracturing injections with diesel fuel, the Class II permitting rules remain in place and govern all such injections.[5]

As the Congressional investigation demonstrates, oil and gas companies ignored these clear requirements.[6] In light of this apparently common failure to comply with the law, EPA would be well within its authority to ban diesel injection entirely. Diesel fuel injection is an inherent threat to safe drinking water. Cf. 42 U.S.C. § 300h(b)(1)(B) (applicants for permits must satisfactorily demonstrate that "the underground injection will not endanger drinking water sources"). Companies can and should be required to avoid using diesel fuel in their operations. But if EPA does not do so, it should at a minimum limit the threats it poses by issuing strong guidance and requiring permits to control injection practices.

Responses to EPA's Discussion Questions

WHAT SHOULD BE CONSIDERED AS "DIESEL FUELS?

The injection of any quantity of diesel fuels for hydraulic fracturing should be covered under EPA's UIC Class II regulations. This includes products derived from, containing, or mixed with diesel fuels or any fuel which could be used in a diesel engine.

At 40 CFR §80.2(x), "diesel fuel" is defined as:

Diesel fuel means any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is—

(1) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel;

(2) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (e.g. , biodiesel fuel); or

(3) A mixture of fuels meeting the criteria of paragraphs (1) and (2) of this definition.

WHAT WELL CONSTRUCTION REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

[5] States which do not enforce against scofflaw injectors risk their primacy, as EPA should make clear. *See* 42 U.S.C. § 300h(c) (providing that if EPA determines that "a state no longer meetings the requirements" of the SDWA, then EPA shall implement a federal program).

[6] Indeed, even diesel injection into wells permitted by rule is barred if the operator did not comply with the Class II regulations. These applicable rules include EPA's inventory requirements at 40 C.F.R. § 144.26, which trigger reporting of well location and operating status, and, for EPA-administered programs, reports on the "nature of injected fluids" and on the mechanical integrity of the well. *See* 40 C.F.R. § 144.22(prohibiting injection without inventory reporting). If operators inject into permitted-by-rule wells without complying with these and other applicable requirements, they further violate the SDWA.

Casing and Cement

Proper well construction is crucial to ensuring protection of USDWs. The first step to ensuring good well construction is ensuring proper well drilling techniques are used. This includes appropriate drilling fluid selection, to ensure that the wellbore will be properly conditioned and to minimize borehole breakouts and rugosity that may complicate casing and cementing operations. Geologic, engineering, and drilling data can provide indications of potential complications to achieving good well construction, such as highly porous or fractured intervals, lost circulation events, abnormally pressured zones, or drilling "kicks" or "shows." These must be accounted for in designing and implementing the casing and cementing program. Reviewing data from offset wellbores can be helpful in anticipating and mitigating potential drilling and construction problems. Additionally, proper wellbore cleaning and conditioning techniques must be used to remove drilling mud and ensure good cement placement.

Hydraulic fracturing requires fluid to be injected into the well at high pressure and therefore wells must be appropriately designed and constructed to withstand this pressure. The casing and cementing program must:

- Properly control formation pressures and fluids
- Prevent the direct or indirect release of fluids from any stratum to the surface
- Prevent communication between separate hydrocarbon-bearing strata
- Protect freshwater aquifers/useable water from contamination
- Support unconsolidated sediments
- Protect and/or isolate lost circulation zones, abnormally pressured zones, and any prospectively valuable mineral deposits

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.

UIC Class II rules require that injection wells be cased and cemented to prevent movement of fluids into or between underground sources of drinking water and that the casing and cement be designed for the life of the well [40 CFR §146.22(b)(1)]. Achieving and maintaining mechanical integrity are crucial to ensuring these requirements. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Internal mechanical integrity refers to the absence of leakage pathways through the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing, primarily through the cement.

The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (GEP), Best Available Technology (BAT), and local and regional engineering and geologic data. All well construction materials

must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

Conductor Casing:

Conductor casing is typically the first piece of casing installed and provides structural integrity and a conduit for fluids to drill the next section of the well. Setting depth is based on local geologic and engineering factors but is generally relatively shallow, typically down to bedrock. Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, the space between the casing and the wellbore – the annulus – should be fully cemented from the base, or "shoe," of the casing to the ground surface, a practice referred to as "cementing to surface." A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

Surface Casing:

Surface casing is used to: isolate and protect groundwater from drilling fluids, hydrocarbons, formation fluids, and other contaminants; provide a stable foundation for blowout prevention equipment; and provide a conduit for drilling fluids to drill the next section of the well.

Surface casing setting depth must be based on relevant engineering and geologic factors, but generally should be:

1. Shallower than any pressurized hydrocarbon-bearing zones
2. 100 feet below the deepest USDW

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of USDWs.

Intermediate Casing:

Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including but not limited to the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost circulation zones, or other drilling hazards. When used, intermediate casing should be fully cemented from the shoe to the surface by the pump and plug method. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (e.g. productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids.

Production Casing:

To be most protective, one long-string production casing (i.e. casing that extends from the total depth of the well to the surface) should be used. This is preferable to the use of a production liner – in which the

casing does not extend to surface but is instead “hung” off an intermediate string of casing – as it provides an additional barrier to protect groundwater. The cementing requirements are the same as for intermediate casing.

Production Liner:
If production liner is used instead of long-string casing, the top of the liner must be hung at least 200 feet above previous casing shoe. The cementing requirements for production liners should be the same as for intermediate and production casing.

General:
For surface, intermediate, and production casing, a sufficient number of casing centralizers must be used to ensure that the casing is centered in the hole and in accordance with API Spec 10D (Specification for Bow-Spring Casing Centralizers) and API RP 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). This is necessary to ensure that the cement is distributed evenly around the casing and is particularly important for directional and horizontal wells. In deviated wells, the casing will rest on the low side of the wellbore if not properly centralized, resulting in gaps in the cement sheath where the casing makes direct contact with the rock. Casing collars should have a minimum clearance of 0.5 inch on all sides to ensure a uniformly concentric cement sheath.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals. This typically applies to the surface casing and possibly conductor casing portions of the hole.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, all surface, intermediate, and production casing strings should be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.22 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

Cement compressive strength tests must be performed on all surface, intermediate, and production casing strings. Casing must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi. The cement mixture must have a 72-hour compressive strength of at least 1200 psi. Additionally, the API free water separation must average no more than six milliliters per 250 milliliters of cement, tested in accordance with API RP 10B-2.

For cement mixtures without published compressive strength tests, the operator or service company must perform such tests in accordance with the current API RP 10B-6 and provide the results of these tests to regulators prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, casing shoe tests should be performed immediately after drilling out of the surface or intermediate casing. These may include Formation Integrity Tests (FIT), Leak-Off Tests (LOT or XLOT), and pressure fall-off or pump tests. Casing shoe tests are used to ensure casing and cement integrity, determine whether the formations below the casing shoe can withstand the pressure to which they will be subjected while drilling the next section of the well, and gather data on rock mechanical properties. If any of the casing shoe tests fail, remedial action must be taken to ensure that no migrations pathways exist. Alternatively, the casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

UIC Class II rules require that cement bond, temperature, or density logs be run after installing surface, intermediate, and production casing and cement [40 CFR §146.22(f)(2)(i)(B)]. Ideally, all three types of logs should be run. The term “cement bond log” refers to out-dated technology and the terms “cement evaluation logs,” “cement integrity logs” or “cement mapping logs” are preferable. Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can allow fluids to move behind casing from the reservoir into USDWs. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation logs is crucial. (For further reading see, e.g., Lockyear et. al, 1990; Frisch et. al, 2005)

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

In addition, it may be useful to review the casing and cementing regulations of states with long histories of oil and gas production such as Texas, Alaska, California, and Pennsylvania. Specific examples include:

- Requirements for casing and cementing record keeping for casing and cementing operations in the California Code of Regulations (CCR) at 14 CCR §1724
- Requirements for casing and cementing program application content in the Alaska Administrative Code (AAC) at 20 AAC §25.030(a)
- Cement chemical and physical degradation standard in the Pennsylvania Code (Pa. Code) at 25 Pa. Code §78.85(a)
- Requirement to report and repair defective casing or take the well out of service in the Pennsylvania Code at 25 Pa. Code §78.86
- Casing standard in gas storage areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with gas storage
- Casing standard in coal development areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with sufficient coal seams
- Casing testing and minimum overlap length standards in the California Code of Regulations at 14 CCR §1722

- Cement quality, testing, and remedial repair standard in the Alaska Administrative Code at 20 AAC §25.030
- Casing quality and amount standard in the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71

Well Logs

After drilling the well but prior to casing and cementing operations, operators must obtain well logs to aid in the geologic, hydrologic, and engineer characterization of the subsurface. Open hole logs, i.e. logs run prior to installing casing and cement, should at a minimum include:

Gamma Ray Logs:

Gamma ray logs detect naturally occurring radiation. These logs are commonly used to determine generic lithology and to correlate subsurface formations. Shale formations have higher proportions of naturally radioactive isotopes than sandstone and carbonate formations. Thus, these formations can be distinguished in the subsurface using gamma ray logs.

Density/Porosity Logs:

Two types of density logs are commonly used: bulk density logs, which are in turn used to calculate density porosity, and neutron porosity logs. While not a direct measure of porosity, these logs can be used to calculate porosity when the formation lithology is known. These logs can be used to determine whether the pore space in the rock is filled with gas or with water.

Resistivity Logs:

These logs are used to measure the electric resistivity, or conversely conductivity, of the formation. Hydrocarbon- and fresh water-bearing formations are resistive, i.e. they cannot carry an electric current. Brine-bearing formations have a low resistivity, i.e. they can carry an electric current. Resistivity logs can therefore be used to help distinguish brine-bearing from hydrocarbon-bearing formations. In combination with Darcy's Law, resistivity logs can be used to calculate water saturation.

Caliper Logs:

Caliper logs are used to determine the diameter and shape of the wellbore. These are crucial in determining the volume of cement that must be used to ensure proper cement placement.

These four logs, run in combination, make up one of the most commonly used logging suites. Additional logs may be desirable to further characterize the formation, including but not limited to Photoelectric Effect, Sonic, Temperature, Spontaneous Potential, Formation Micro-Imaging (FMI), Borehole Seismic, and Nuclear Magnetic Resonance (NMR). The use of these and other logs should be tailored to site-specific needs. (For further reading see, e.g., Asquith and Krygowski, 2004)

UIC Class II rules have specific logging requirements "(f)or surface casing intended to protect underground sources of drinking water in areas where the lithology has not been determined" [40 CFR §146.22(f)(2)(i)]. For such wells, electric and caliper logs must be run before surface casing is installed [40 CFR §146.22(f)(2)(i)(A)]. Such logs should be run on all wells, not just those where lithology has not been determined, and the electric logs suite should include, at a minimum, caliper, resistivity and gamma ray or spontaneous potential logs. For intermediate and long string casing "intended to facilitate injection," UIC Class II rules require that electric porosity, gamma ray, and fracture finder logs be run

before casing is installed [40 CFR §146.22(f)(2)(ii)(A) and (B)]. Hydraulic fracturing should be included in the definition of "injection." Operators should also run caliper and resistivity logs. The term "fracture finder logs" refers to out-dated technology. More advanced tools for locating fractures should be used, such as borehole imaging logs (e.g. FMI logs) and borehole seismic.

Core and Fluid Sampling

While not specifically required by current UIC Class II regulations, operators of wells that will be hydraulically fractured using diesel should also obtain whole or sidewall cores of the producing and confining zone(s) and formation fluid samples from the producing zone(s). At a minimum, routine core analysis should be performed on core samples representative of the range of lithology and facies present in the producing and confining zone(s). Special Core Analysis (SCAL) should also be considered, particularly for samples of the confining zone, where detailed knowledge of rock mechanical properties is necessary to determine whether the confining zone can prevent or arrest the propagation of fractures. Operators should also record the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the producing and confining zone(s). Operators should prepare and submit a detailed report on the physical and chemical characteristics of the producing and confining zone(s) and formation fluids that integrates data obtained from well logs, cores, and fluid samples. This must include the fracture pressure of both the producing and confining zone(s).

WHAT WELL OPERATION, MECHANICAL INTEGRITY, MONITORING, AND REPORTING REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

Mechanical Integrity

Operators must maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on site and operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

Operations and Monitoring

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model, as described in the Area of Review requirements, prior to operation to ensure that the treatment will not endanger USDWs. Prior to performing a hydraulic fracturing treatment, operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

The hydraulic fracturing operation must be carefully and continuously monitored. In API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, the

America Petroleum Institute recommends continuous monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss of mechanical integrity or if injection pressure exceeds the fracture pressure of the confining zone(s), the operation must immediately cease. If either occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered or if the integrity of the confining zone has been compromised, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design. Tiltmeters measure small changes in inclination and provide a measure of rock deformation. Microseismic monitoring uses highly sensitive seismic receivers to measure the very low energy seismic activity generated by hydraulic fracturing (For further reading see, e.g., House, 1987; Maxwell et al., 2002; Le Calvez et al., 2007; Du et al., 2008; Warpinski et al., 2008; Warpinski, 2009; and Cipolla et al. 2011).

Hydraulic fracturing fluid and proppant can sometimes be preferentially taken up by certain intervals or perforations. Tracer surveys and temperature logs can be used to help determine which intervals were treated. Tracers can be either chemical or radioactive and are injected during the hydraulic fracturing operation. After hydraulic fracturing is completed, tools are inserted into the well that can detect the tracer(s). Temperature logs record the differences in temperature between zones that received fracturing fluid, which is injected at ambient surface air temperature, and in-situ formation temperatures, which can be in the hundreds of degrees Fahrenheit.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to

characterize seasonal variations in water chemistry. Monitoring should continue a minimum of 5 years prior to plugging and abandonment.

Reporting

At a minimum, operators must report:

- All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit
- All instances of an indication of loss of mechanical integrity
- Any failure to maintain mechanical integrity
- The results of:
    - Continuous monitoring during hydraulic fracturing operations
    - Techniques used to measure actual fracture growth
    - Any mechanical integrity tests
- The detection of the presence of contaminants pursuant to the groundwater quality monitoring program
- Indications that injected fluids or displaced formation fluids may pose a danger to USDWs
- All spills and leaks
- Any non-compliance with a permit condition

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:

1. Baseline water quality analyses for all USDWs within the area of review
2. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
3. Proposed chemical additives (including proppant coating), reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:

1. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
2. Actual chemical additives used, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
3. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

Emergency and Remedial Response

Operators must develop, submit, and implement an emergency response and remedial action plan. The plan must describe the actions the operator will take in response to any emergency that may endanger

human life or the environment – including USDWs – such as blowouts, fires, explosions, or leaks and spills of toxic or hazardous chemicals. The plan must include an evaluation of the ability of local resources to respond to such emergencies and, if found insufficient, how emergency response personnel and equipment will be supplemented. Operators should detail what steps they will take to respond to cases of suspected or known water contamination, including notification of users of the water source. The plan must describe what actions will be taken to replace the water supplies of affected individuals in the case of the contamination of a USDW.

The American Petroleum Institute has published recommended practices for developing a Safety and Environmental Management System (SEMS) plan, API Recommended Practice 75L: Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operation and Associated Activities. This may be a useful document to reference when developing guidance.

WHAT SHOULD THE PERMIT DURATION BE AND HOW SHOULD CLASS II PLUGGING AND ABANDONMENT PROVISIONS BE ADDRESSED FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

The permit should be valid for the life of the well. However, operators must request and receive approval prior to performing any hydraulic fracturing operations that occur subsequent to the initial hydraulic fracturing operation for which the permit was approved. This can be accomplished by means of a sundry or amended permit. Operators must provide updates to all relevant permit application data to the regulator.

Prior to plugging and abandoning a well, operators should determine bottom hole pressure and perform a mechanical integrity test to verify that no remedial action is required. Operators should develop and implement a well plugging plan. The plugging plan should be submitted with the permit application and should include the methods that will be used to determine bottom hole pressure and mechanical integrity; the number and type of plugs that will be used; plug setting depths; the type, grade, and quantity of plugging material that will be used; the method for setting the plugs, and; a complete wellbore diagram showing all casing setting depths and the location of cement and any perforations.

Plugging procedures must ensure that hydrocarbons and fluids will not migrate between zones, into USDWs, or to the surface. A cement plug should be placed at the surface casing shoe and extend at least 100 feet above and below the shoe. All hydrocarbon-bearing zones should be permanently sealed with a plug that extends at least 100 feet above and below the top and base of all hydrocarbon-bearing zones. Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe. In the case of an open hole completion, any hydrocarbon- or fluid-bearing zones shall be isolated by cement plugs set at the top and bottom of such formations, and that extend at least 100 feet above the top and 100 feet below the bottom of the formation.

At least 60-days prior to plugging, operators must submit a notice of intent to plug and abandon. If any changes have been made to the previously approved plugging plan the operator must also submit a revised plugging plan. No later than 60-days after a plugging operation has been completed, operators

must submit a plugging report, certified by the operator and person who performed the plugging operation.

After plugging and abandonment, operators must continue to conduct monitoring and provide financial assurance for an adequate time period, as determined by the regulator, that takes into account site-specific characteristics including but not limited to:

- The results of hydrologic and reservoir modeling that assess the potential for movement of contaminants into USDWs over long time scales.
- Models and data that assess the potential degradation of well components (e.g. casing, cement) over time and implications for mechanical integrity and risks to USDWs.

WHAT SHOULD THE TIME FRAME BE FOR SUBMITTING A PERMIT FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

All operators who wish to drill a Class II well using diesel fuel for hydraulic fracturing must submit a permit application to the regulator. Permit applications should be submitted within a reasonable timeframe but no less than 30 days prior to when the operator intends to begin construction. Under no circumstances shall activity commence until the application is approved and a permit is issued.

WHAT ARE IMPORTANT SITING CONSIDERATIONS?

Site Characterization & Planning

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. Site characterization and planning must take into account cumulative impacts over the life of a project or field.

Operators must submit to the regulator a statistically significant sample, as determined by the regulator, of existing and/or new geochemical analyses of each of the following, within the area of review:

1. Any and all sources of water that serve as USDWs in order to characterize baseline water quality. This data must be made publically available through an online, geographically-based reporting system. The sampling methodology must be based on local and regional hydrologic characteristics such as rates of precipitation and recharge and seasonal fluctuations. At a minimum, characterization must include:
    a. Standard water quality and geochemistry[7]
    b. Stable isotopes
    c. Dissolved gases
    d. Hydrocarbon concentration and composition. If hydrocarbons are present in sufficient quantities for analysis, isotopic composition must be determined

[7] Including: Turbidity, Specific Conductance, Total Solids, Total Dissolved Solids, pH, Dissolved Oxygen, Redox State, Alkalinity, Calcium, Magnesium, Sodium, Potassium, Sulfate, Chloride, Fluoride, Bromide, Silica, Nitrite, Nitrate + Nitrite, Ammonia, Phosphorous, Total Organic Carbon, Aluminum, Antimony, Arsenic, Barium, Beryllium, Boron, Bromide, Cadmium, Chromium, Cobalt, Copper, Cyanide, Iron, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Silver, Strontium, Thallium, Thorium, Uranium, Vanadium, Zinc, Cryptosporidium, Giardia, Plate Count, Legionella, Total Coliforms, and Organic Chemicals including Volatile Organic Compounds (VOCs)

    e. Chemical compounds or constituents thereof, or reaction products that may be introduced by the drilling or hydraulic fracturing process. The use of appropriate marker chemicals is permissible provided that the operator can show scientific justification for the choice of marker(s).

   Operators should also consider testing for environmental tracers to determine groundwater age.
2. Any hydrocarbons that may be encountered both vertically and areally throughout the area of review;
3. The producing zone(s) and confining zone(s) and any other intervening zones as determined by the regulator. At a minimum, characterization must include:
    a. Mineralogy
    b. Petrology
    c. Major and trace element bulk geochemistry

Operators of wells that will be hydraulically fractured must demonstrate to the satisfaction of the regulator that the wells will be sited in a location that is geologically suitable. In order to allow the regulator to determine suitability, the owner or operator must provide:

1. A detailed analysis of regional and local geologic stratigraphy and structure including, at a minimum, lithology, geologic facies, faults, fractures, stress regimes, seismicity, and rock mechanical properties.
2. A detailed analysis of regional and local hydrology including, at a minimum, hydrologic flow and transport data and modeling and aquifer hydrodynamics; properties of the producing and confining zone(s); groundwater levels for relevant formations; discharge points, including springs, seeps, streams, and wetlands; recharge rates and primary zones, and; water balance for the area including estimates of recharge, discharge, and pumping
3. A detailed analysis of the cumulative impacts of hydraulic fracturing on the geology of producing and confining zone(s) over the life of the project. This must include, but is not limited to, analyses of changes to conductivity, porosity, and permeability; geochemistry; rock mechanical properties; hydrologic flow; and fracture mechanics.
4. A determination that the geology of the area can be described confidently and that the fate and transport of injected fluids and displaced formation fluids can be accurately predicted through the use of models.

Wells that will be hydraulically fractured must be sited such that a suitable confining zone is present. The operator must demonstrate to the satisfaction of the regulator that the confining zone:

1. Is of sufficient areal extent to prevent the movement of fluids to USDWs, based on the projected lateral extent of hydraulically induced fractures, injected hydraulic fracturing fluids, and displaced formation fluids over the life of the project;
2. Is sufficiently impermeable to prevent the vertical migration of injected hydraulic fracturing fluids or displaced formation fluids over the life of the project;
3. Is free of transmissive faults or fractures that could allow the movement of injected hydraulic fracturing fluids or displaced formation fluids to USDWs; and

4. Contains at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing or arresting vertical propagation of fractures.
5. The regulator may require operators of wells that will be hydraulically fractured to identify and characterize additional zones that will impede or contain vertical fluid movement.

The site characterization and planning data listed above does not have to be submitted with each individual well application as long as such data is kept on file with the appropriate regulator and the well for which a permit is being sought falls within the designated area of review.

WHAT SUGGESTIONS DO YOU HAVE FOR REVIEWING THE AREA AROUND THE WELL TO ENSURE THERE ARE NO CONDUITS FOR FLUID MIGRATION, SEISMICITY, ETC.?

The area of review should be the region around a well or group of wells that will be hydraulically fractured where USDWs may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated hydraulic fracturing pressures, rates, and volumes.
2. Geologic and engineering heterogeneities
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations.
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model must be updated and history matched. Operators must develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation.

Within the area of review, operators must identify all wells that penetrate the producing and confining zones and provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require. If any the wells identified are improperly constructed, completed, plugged, or abandoned, corrective action must be taken to ensure that they will not become conduits for injected or formation fluids to USDWs. Operators must develop, submit, and implement a corrective action plan.

WHAT INFORMATION SHOULD BE SUBMITTED WITH THE PERMIT APPLICATION?

In addition to the requirements at 40 CFR §146.24, operators should also submit the following information:

1. Information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and confining zone(s), consistent with Site Characterization and Planning requirements, including:
    a. Maps and cross-sections of the area of review
    b. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not provide migration pathways for injected fluids or displaced formation fluids to USDWs
    c. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions
    d. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)
    e. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)
    f. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area
    g. Hydrologic flow and transport data and modeling
2. A list of all wells within the area of review that penetrate the producing or confining zone and a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require.
3. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known
4. Baseline geochemical analyses of USDWs, hydrocarbons, and the producing and confining zone, consistent with the requirements for Site Characterization & Planning
5. Proposed area of review and corrective action plan that meet the Area of Review and Corrective Action Plan requirements
6. A demonstration that the operator has met the financial responsibility requirements
7. Proposed pre-hydraulic fracturing formation testing program to analyze the physical and chemical characteristics of the producing and confining zone(s), that meet the Well Log, Core, Fluid Sampling, and Testing requirements
8. Well construction procedures that meet the Well Construction requirements
9. Proposed operating data for the hydraulic fracturing operation:
    a. Operating procedure
    b. Calculated fracture gradient of the producing and confining zone(s)

    c. Maximum pressure, rate, and volume of injected fluids and proppant and demonstration that the proposed hydraulic fracturing operation will not initiate fractures in the confining zone or cause the movement of hydraulic fracturing or formation fluids that endangers a USDW
10. Proposed chemical additives:
    a. Service companies and operators must report all proposed additives by their type (e.g. breaker, corrosion inhibitor, proppant, etc), chemical compound or constituents, and Chemical Abstracts Service (CAS) number
    b. Service companies and operators must report the proposed concentration or rate and volume percentage of all additives
11. Proposed testing and monitoring plan that meets the testing and monitoring plan requirements
12. Proposed well plugging plan that meets the plugging plan requirements
13. Proposed emergency and remedial action plan
14. Prior to granting final approval for a hydraulic fracturing operation, the regulator should consider the following information:
    a. The final area of review based on modeling and using data obtained from the logging, sampling, and testing procedures
    b. Any updates to the determination of geologic suitability of the site and presence of an appropriate confining zone based on data obtained from the logging, sampling, and testing procedures
    c. Information on potential chemical and physical interactions and resulting changes to geologic properties of the producing and confining zone(s) due to hydraulic fractures and the interaction of the formations, formation fluids, and hydraulic fracturing fluids, based on data obtained from the logging, sampling, and testing procedures
    d. The results of the logging, sampling, and testing requirements
    e. Final well construction procedures that meet the well construction requirements
    f. Status of corrective action on the wells in the area of review
    g. A demonstration of mechanical integrity
    h. Any updates to any aspect of the plan resulting from data obtained from the logging, sampling, and testing requirements.

HOW COULD CLASS II FINANCIAL RESPONSIBILITY REQUIREMENTS BE MET FOR WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

Operators must demonstrate and maintain financial responsibility by means of a bond, letter of credit, insurance, escrow account, trust fund, or some combination of these financial mechanisms or any other mechanism approved by the regulator. The financial responsibility mechanism must cover the cost of corrective action, well plugging and abandonment, emergency and remedial response, long term monitoring, and any clean up action that may be necessary as a result of contamination of a USDW.

WHAT PUBLIC NOTIFICATION REQUIREMENTS OR SPECIAL ENVIRONMENTAL JUSTICE CONSIDERATIONS SHOULD BE CONSIDERED FOR AUTHORIZATION OF WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

EPA must ensure that there are opportunities for public involvement and community engagement throughout all steps of the process.

1. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:
    a. Baseline water quality analyses for all USDWs within the area of review
    b. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
    c. Proposed chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives
2. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:
    a. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
    b. Actual chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
    c. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

WHAT ARE EFFICIENT ALTERNATIVES TO AUTHORIZE/PERMIT CLASS II WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

The use of area permits should not be allowed for wells that use diesel fuel for hydraulic fracturing. Each hydraulic fracturing operation is unique and designed for site-and well-specific needs. The fluid volumes required, chemical make-up of hydraulic fracturing fluid, and geology and hydrology of the producing and confining zones can vary from well to well.

In situations where multiple wells will be drilled from the same surface location or pad, it may be permissible to issue a group permit for all such wells. In requesting a group permit, operators must provide the regulator with an analysis demonstrating that the geology, hydrology, and operating parameters of all wells are sufficiently similar such that the issuance of a group permit will not pose increased risks to USDWs as compared to individual permits. If a group permit is approved, operators must still disclose information on injected chemicals for each individual well unless the type and volume of chemicals injected will be identical for each well. Operators must also still provide geochemical analyses of flowback and produced water for each individual well.

Conclusions

Thank you for your consideration of these comments. We are pleased that EPA is undertaking this effort to develop permitting guidance for hydraulic fracturing using diesel fuel. While this guidance is crucial to ensure that no further unpermitted hydraulic fracturing using diesel occurs, we urge EPA to begin the process of drafting new regulation that specifically addresses the unique risks hydraulic fracturing poses to USDWs.

Sincerely,

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