Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

Supporting Information

1. Graphical Representation of the Fuel Life-cycles

Figure 1S and Figure 2S below, show the life-cycle stages on natural gas used by electric power generators, including the stages from the LNG life-cycle. Notice that local distribution of natural gas falls outside our analysis boundary.

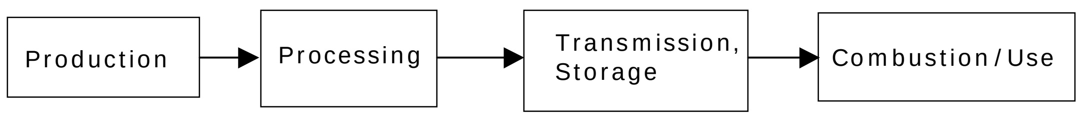

Figure 1S: Domestic Natural Gas Life-cycle.

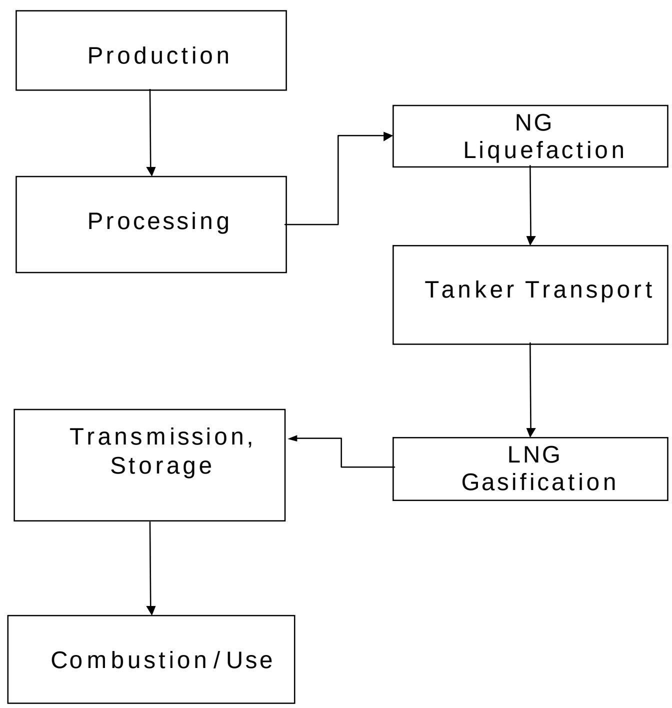

Figure 2S: LNG Life-cycle.

Figure 3S and Figure 4S show the life-cycle of coal and synthetic natural gas (SNG) derived from coal.

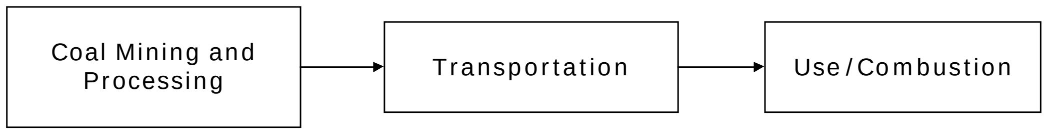

Figure 3S: Coal Life-cycle.

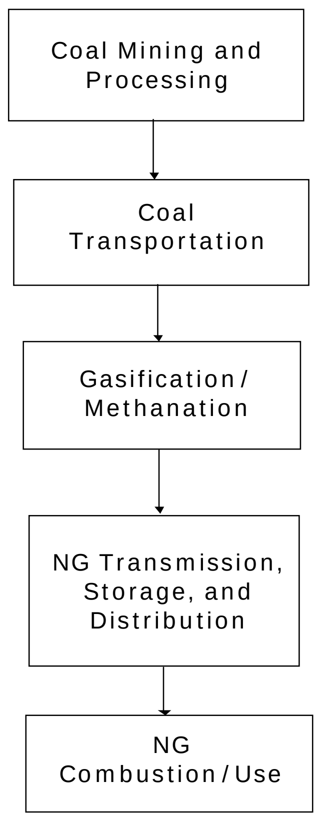

Figure 4S: SNG Life-cycle.

2. Calculating Emissions from the Domestic Natural Gas Life-cycle

During the late 1980s and early 1990s the U.S. Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry (1). This comprehensive study developed hundreds of activity and emissions factors from all areas of the natural gas industry. These factors were developed using data collected from different sectors of the industry as well as from data collected in field measurements. Methane emissions from the U.S. natural gas system given as a percentage of natural gas produced can be seen in Table 1S. This data was used to develop methane emission factors, as described in the main document. Notice, that Table 1S includes an estimate for natural gas losses in the local distribution system. This estimate is given here for reference, but it was not included in our calculation of emissions of natural gas used to generate electricity.

In addition data from the EPA Natural Gas STAR program was used. The program is a voluntary partnership with the goal of encouraging the natural gas industry to adopt practices that increase efficiency and reduce emissions (for example by reducing natural gas leaks in the pipeline system). Consequently, since 1993, a cumulative total of 338 billion cubic feet of methane emissions have been eliminated. In 2003 alone, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (2).

Table 1S: Methane Emissions from North American Gas Life-cycle as a Percentage of Natural Gas Produced (1).

Lifecycle Segment	Emissions as a Percentage of Gas Produced
Production	0.38%
Processing	0.16%
Transmission and Storage	0.53%
Distribution	0.35%

Carbon dioxide emissions from the different natural gas life-cycle stages were also calculated. These emissions were calculated using data on the amount of natural gas used to run the processes, as given in Table 2S, as well as an estimated 3 billion KWh of electricity used for pipeline transport. These data were also used to calculate SO_x and NO_x emissions from the life-cycle, as described in the main document. It should be mentioned that the pipeline fuel presented in Table 2S includes fuel used by the transmission system and the local distribution system. As previously described, natural gas used by electricity generators is bought directly from the transmission system, so that emissions from the distribution system are not included in our analysis. Due to data limitations, we were not able to disaggregate pipeline fuel and electricity consumption between the two systems. To deal with this issue, we use a range of emissions. The minimum value assumes that none of this fuel is consumed in the transmission system and the maximum value assumes that all is consumed in the transmission system.

Table 2S: Natural Gas Used During the Natural Gas Life-cycle. (3).

Use (as defined by EIA)	NG Life-cycle Stage	Amount (million ft^3)
Flared Gas	Production	98,000
Lease Fuel	Production	760,000
Pipeline Use	Transmission/Distribution	665,000
Plant Fuel	Processing	365,000

3. Calculating Emissions from the LNG Life-cycle

As mentioned in the main paper, Tamura et al (4) provide GHG emissions for liquefaction plants. Table 3S presents the sources of these emissions.

Table 3S: Liquefaction Emission Factors (Adapted from Tamura et al (4)).

Liquefaction	Emission Factors (lb CO_2 Equivalent/MMBtu)		
	Minimum	Average	Maximum
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Table 4S provides the distance from LNG exporting countries to two U.S. LNG terminals and the amount of LNG brought from each country in 2003. These two terminals were chosen because they are two of the largest terminals in the United States and they represent longest and shortest tanker travel distances for which route information is available. In addition, the range of distances provided is also representative of distances LNG would have to travel if a LNG terminal was located in the U.S. West Coast. Figure 5S shows the emission factors for LNG Tanker transport from each country to each of these terminals, obtained using the tanker information given in the main document. Emissions from tanker transport range between 2 and 17 pounds of CO_2 Equivalent per MMBtu of natural gas. These data was also used to calculate the SO_x and NO_x emission factors for tanker transport.

Table 4S: LNG Exporting Countries in 2003.

Exporting Country	Distance to Lake Charles Facility (nautical miles) (5)	Distance to Everett, MA Facility (nautical miles) (5)	2003 US Imports (million cubic feet NG) (3)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

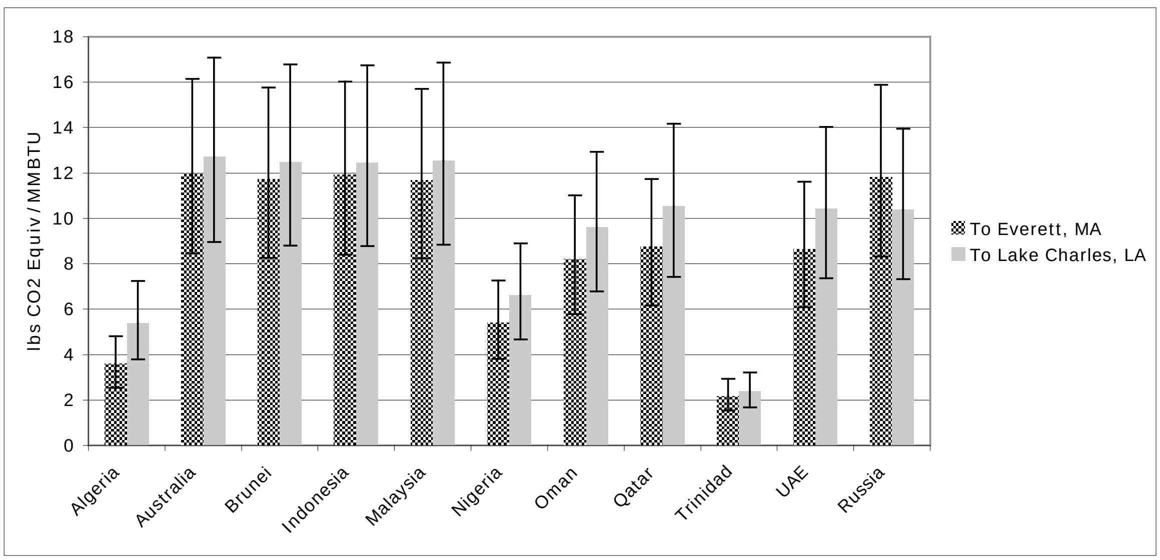

Figure 5S: Tanker Emission Factors from Each Country.

4. Calculating Emissions from the Coal Life-cycle

Table 5S presents fuel consumption data for coal mines in the U.S., and Table 6S presents carbon content, heat content of these fuels. These data was used to calculate GHG emissions factors for coal mines.

Table 5S: 1997 Fuel Consumption at Coal Mines (6)

Mine Type	Fuel Oil (1000 bbl)			Gas (10^9 ft^3)	Gasoline (10^6 gal)	Electricity (10^6 KWh)
	Total	Distillate	Residual			
Surface	8,280	7,524	756	0.7	30	42,474
Underground	801	656	145	0.5	4	7,123

Table 6S: Carbon Content, and Heat Content of Different Fuels (7).

Fuel Type	Carbon Content of Fuel lb/MMBtu Fuel	Heat Content of Fuel (MMBtu/bbl - MMBtu/MMcf)	Fraction Oxidized
Distillate	43.98	5.825	0.99
Residual	47.38	6.287	0.99
Gas	31.90	1,030	0.995
Gasoline	42.66	5.253	0.99

Table 7S: 1997 Coal Production Data (8).

Mine Type	Coal Produced (1000 tons)	Heat Content of Coal (BTU/lb)
Surface	669,273	9,626
Underground	420,657	11,944
Total	1,089,930	10,520

As described in the main document, EIO-LCA was used to estimate emission factors from coal transportation. Table 8S summarizes the emissions resulting from transporting one million ton-miles of coal via each transportation mode.

Table 8S: EIO-LCA GHG Emission Data for a Million Ton-Miles of Coal Transported (9).

Sector	Total GHG Emissions (tons CO_2 Equivalent)	Total SO_x Emissions (tons SO_x)	Total NO_x Emissions (tons NO_x)
Rail Transportation	43.6	0.02	0.40
Water Transportation	5.89	0.07	0.36
Truck Transportation	69.0	0.06	1.42

5. Calculating Emissions from the SNG Life-cycle

In order to calculate air emissions from the SNG life-cycle, the emissions from coal production, processing and transport were converted from pounds per MMBtu of coal used to pounds per MMBtu of SNG produced using the performance characteristics of two SNG plants given in Table 9S. The emissions from SNG transport, storage and use are the same as those from natural gas. The efficiency for the CCS case was obtained assuming an energy penalty of 16% as described for and IGCC plant by Rubin et al (10).

Table 9S: SNG Plant Performance Characteristics

	Case 1 (11)	Case 2 (12)
SNG Output (1. mcf/day and 2. MMBtu/hr)	250	1,739
Efficiency without CCS (HHV)	57%	60%
Efficiency with CCS (HHV)	50%	52%

6. Summary of Emissions from Fuel Life-cycles

Table 10S summarizes GHG emission factors for all fuels. The emission factors presented in this section are the average emission rate relative to units of fuel produced, without considering the efficiency of using these fuels. These emission factors can later be used to develop total inventories of GHG emissions from the annual consumption of each fuel. Allocation of these emissions for each life-cycle stage can be seen in Figure 6S through Figure 8S. Note that there are two different emission factors for SNG. In one case, no carbon capture and sequestration (CCS) is performed at the gasification-methanation stage. When CCS is performed at the gasification-methanation plant, an energy penalty is incurred. It was assumed that the energy penalty observed at IGCC plants with CCS (16%) is representative of the energy penalty at the SNG gasification-methanation plant (10). CCS could also be performed at power plants, as discussed in the main document.

It is also very important to note that the emission factors shown in Table 10**S** (and the emission factors given in Table 11S) are not comparable to each other, since one Btu of coal does not generate the same amount of electricity as one Btu of natural gas or SNG. These emission factors can be transformed to comparable units, namely lbs/MWh of electricity produced, by taking into consideration the efficiency of electricity generation.

Table 10S: Life-cycle GHG Emission Factors

(units: lbs/MMBtu of Fuel Produced)

Life-cycle Stages	North American NG		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Upstream	15.3	20.1	29.6	72.3	8.2	16.4	240	286	45.2	65.2
Combustion (no CCS)	120	120	120	120	205	205	120	120	120	120
Combustion (with CCS)	12	12	12	12	20.5	20.5	12	12	12	12

SO_x and NO_x emission factors for the upstream stages of electricity generation for the fuel life-cycles can be seen in Table 11S. SO_x and NO_x emissions from the combustion of fuel at power plants are very dependent on specific plant characteristics, so it was not possible to transform these power plant emissions (given in lbs/MWh) to the same units as the emissions from the upstream stages of the life-cycle (lbs/MMBtu) by simply using the efficiency of the power plants.

Table 11S: Upstream SO_x and NO_x Emission Factors (units: lbs/MMBtu of Fuel Produced)

Pollutant	North American Natural Gas		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
SO_x	0.006	0.030	0.016	0.145	0.007	0.029	0.051	0.316	0.064	0.400
NO_x	0.009	0.342	0.022	0.831	0.030	0.535	0.090	0.234	0.104	0.253

7. GHG Emissions Allocated to Fuel Life-cycle Stages

Figure 6S through Figure 8S show how the GHG emissions reported in Table 10S are allocated among the different life-cycle stages.

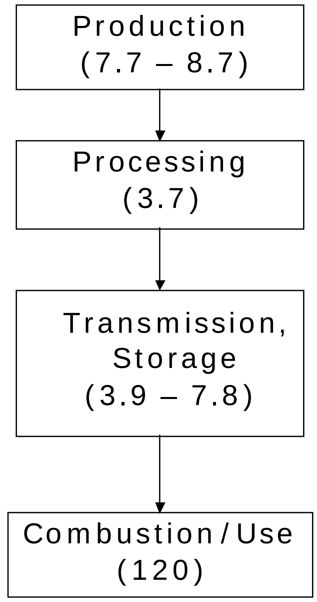

Figure 6S: North American Gas Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

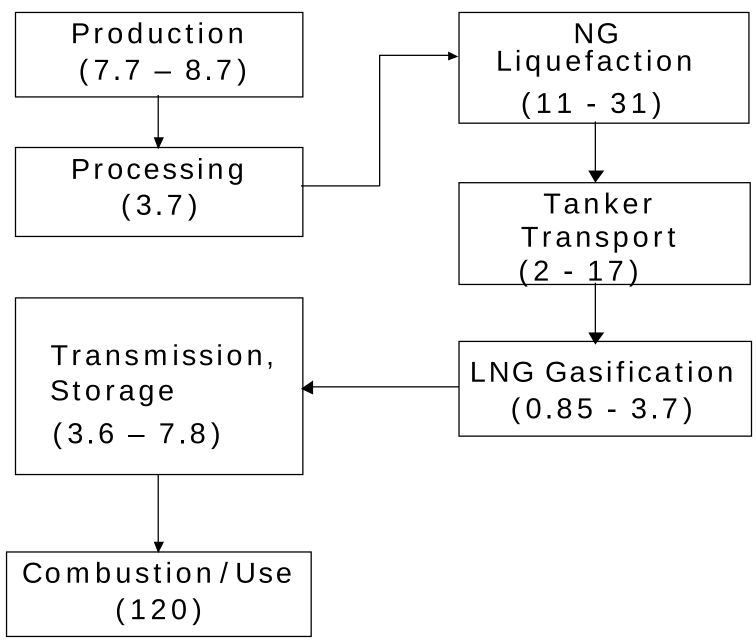

Figure 7S: LNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

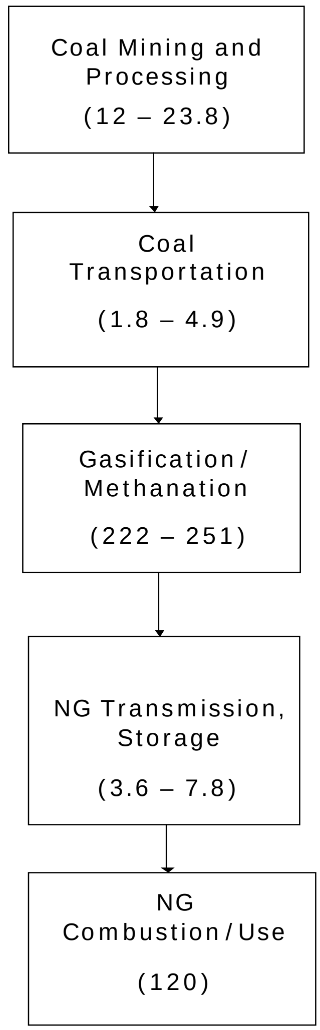

Figure 8S: SNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

8. Efficiencies of Currently Operating Power Plants

Figure 9S shows the distribution of the efficiencies of currently operating power plants, obtained using the cumulative distribution function of EIA 2003 electricity generation data for all utility plants (13). As illustrated in Figure 9S, the median efficiency for natural gas plants is higher than the median efficiency for coal plants. These efficiencies were used to convert the emission factors previously presented (in lbs/ MMBtu of fuel) to lbs/MWh.

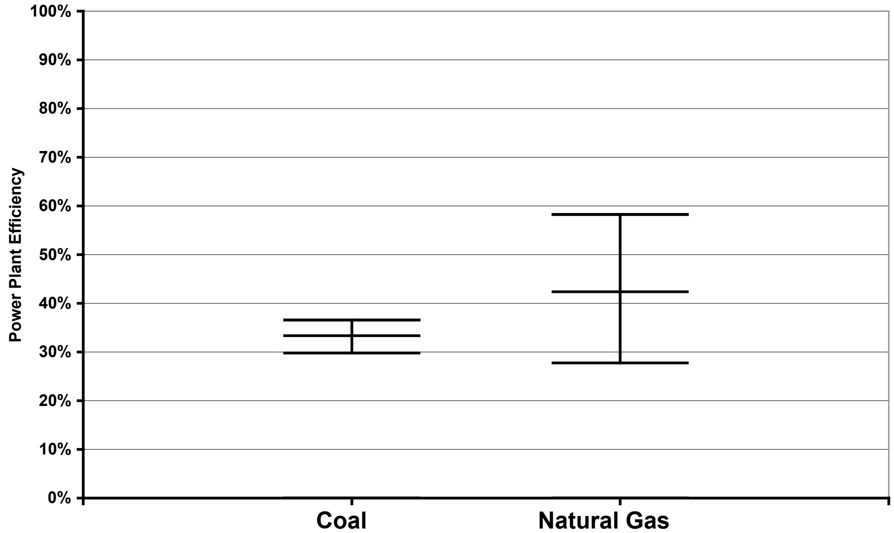

Figure 9S: Efficiencies of Natural Gas and Coal Plants (13).

9. Combustion Emissions from Advance Technologies

Table 12S reports combustion emissions from advanced power plant technologies. The emission factors from PC and IGCC plants were reported Bergerson (14) for PC and IGCC plants. Rubin et al reported the emissions for NGCC plants (10).

Table 12S: Combustion Emissions from Advanced Power Plants.

Fuel/Pollutant	SO_x (lbs/MWh)		NO_x (lbs/MWh)	
	Min	Max	Min	Max
PC w/o CCS	0.17	1.28	1.16	2.00
PC w/ CCS	0.00	0.01	1.56	3.00
IGCC w/o CCS	0.20	1.30	0.20	0.20
IGCC w/ CCS	0.24	1.52	0.20	0.20
NGCC w/o CCS	0.00	0.00	0.24	0.24
NGCC w/ CCS	0.00	0.00	0.29	0.29

10. References

(1) EPA "Methane Emission From the Natural Gas Industry," Environmental Protection Agency, 1996.
(2) EPA "Natural Gas Star Program Accomplishments," Voluntary Methane Partnership Programs, 2005.
(3) DOE "Natural Gas Annual 2003," Energy Information Administration, 2004.

(4) Tamura, I.; Tanaka, T.; Kagajo, T.; Kuwabara, S.; Yoshioka, T.; Nagata, T.; Kurahashi, K.; Ishitani, H. M. S., Life Cycle CO2 Analysis of LNG and City Gas. *Applied Energy* **2001**, *68*, 301-319.
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(6) Comerce, U. S. D. o. "1997 U.S. Economic Census," U.S. Census Bureau, 2001.
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(8) DOE "Coal Industry Annual 1997," Energy Information Administration, 1997.
(9) CMU, Economic Input-Output Life Cycle Assessment Model; www.eiolca.net (accessed May 9, 2006)
(10) Rubin, E. S.; Rao, A. B.; Chen, C. In *Proceedings of 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7)*: Vancouver, Canada, 2004.
(11) Beychok, M. R. "Process & Environmental Technology for Producing SNG & Liquid Fuels," U.S. Environmental Protection Agency, 1975.
(12) Gray, D.; Salerno, S.; Tomlinson, G. "Potential Application of Coal-Derived Fuel Gases for the Glass Industry: A Scoping Analysis," National Energy Technology Laboratory, DOE, 2004.
(13) DOE "Combined (Utility, Non-Utility, and Combined Heat & Power Plant) Database in Excel Format," Energy Information Administration, 2003.
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Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation

Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews

Introduction

Natural gas currently provides 24% of the energy used by homes and businesses in the US (1). It is also an important feedstock for the chemical and fertilizer industry. In the early 1990's the price of natural gas was low (around \$3/1000 ft^3) and as a result there was a surge in construction of natural gas plants (2). Today, the Henry Hub price of natural gas is around \$15/1000 ft^3 (3), and most of these plants are operating below capacity. However, natural gas consumption is expected to increase 41% by 2025 (to 30 trillion cubic feet), with demand from electricity generators growing the fastest (increasing 90% by 2025). At the same time natural gas production in North America is expected to remain fairly constant at around 24 trillion cubic feet, so that demand of imported liquefied natural gas (LNG) will increase to around 6 trillion cubic feet or 20% of the total supply by 2025 (3).

The natural gas system is the second largest source of greenhouse gas emissions in the US, generating around 132 million tons of CO_2 Equivalents (1). Several studies have performed emission inventories for the natural gas lifecycle from production to distribution. Usually these analyses have been performed for domestic natural gas, so that emissions from the LNG lifecycle stages have been ignored. If, as the DOE estimates suggest, larger percentages of the supply of natural gas will come from these imports, emissions from these steps in the lifecycle could influence the total natural gas lifecycle emissions. Thus, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform an analysis of the natural gas lifecycle greenhouse gas emissions taking the emissions from LNG into consideration. Different scenarios for the percentage of natural gas as LNG are analyzed. Moreover, a comparison with the coal fuel cycle greenhouse gas emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

The Natural Gas Life Cycle

The natural gas life cycle starts with the production of natural gas and ends at the combustion plant. NaturalGas.org has a very detailed description of this life cycle. Readers are encouraged to visit this website if they need more information about the topic.

Geological surveys and seismic studies are used to determine the location of natural gas deposits. After these sites have been identified, wells are constructed. There are two types of well for the extraction of natural gas: oil wells and natural gas wells. Oil wells are drilled primarily to extract oil, but natural gas can also be obtained. Natural gas wells are specifically drilled to extract natural gas.

After natural gas is extracted through the wells, it has to be processed to meet the characteristics of the natural gas used by consumers. Consumer natural gas is composed primarily of methane. However, when natural gas is extracted, it exists with other hydrocarbons such as propane and ethane. In addition, the extracted natural gas contains impurities such as water vapor and carbon dioxide that must be removed. Natural gas processing plants are usually constructed in gas producing regions. The natural gas is transported from the extraction sites to these plants through a system of low-diameter, low-pressure pipelines. At the plant, water vapor is first removed from the gas by using absorption or adsorption methods. Glycol Dehydration is an example of absorption, in which glycol, which has a chemical affinity to water, is used to absorb the vapor. Solid-Desiccant Dehydration is an example of adsorption. In this process the natural gas passes through towers that contain activated alumina or other solid desiccants. As the gas is passed through these towers, the water particles are retained on the surface of the solids.

As previously mentioned, natural gas is extracted with other hydrocarbons that must be removed. The removal of these hydrocarbons, called Natural Gas Liquids (NGL), is done with the absorption method or the cryogenic expander process. The absorption method is similar to the water absorption method, but instead of glycol, absorbing oil is used. The cryogenic expansion method consists of dropping the temperatures of the gas causing the hydrocarbons to condense so that they can be separated from the natural gas. The absorption method is used to remove heavier hydrocarbons, while lighter hydrocarbons are removed using the cryogenic expansion process.

The final step in the processing of natural gas is the removal of sulfur and carbon dioxide. Often, natural gas from the wells contains high amounts of these two compounds, and it is called sour gas. Sulfur must be removed from the gas because it is a potentially lethal chemical if breathed. In addition, sour gas can be corrosive for the transmissions and distribution pipelines. The process of removing sulfur and carbon dioxide from the gas is similar to the absorption processes previously described.

After the natural gas is processed it enters the transmission system. In the US, this transmission system is the interstate natural gas pipeline network, which consists of thousands of miles of high-pressure pipelines that transport the gas from producing areas to high demand areas. In addition to the pipes, this pipeline system has compressor stations along the way, usually placed in 40 to 100 mile intervals. These compressor stations use a turbine or an engine to compress the natural gas and maintain the high pressure required in the pipeline. The turbines and engines generally run with a small amount of the gas from the pipeline. In addition to compressor stations, metering stations are also placed along the system to allow companies to better monitor and manage the natural gas in the pipes. Moreover valves can be found through the entire length of the pipelines to regulate flow.

Natural gas can be stored to meet seasonal demand increases or to meet sudden, short-term demand increases. Natural gas is usually stored in underground facilities. Such facilities could be built in reconditioned depleted gas reservoirs, aquifers or salt caverns. According to the Energy Information Administration (EIA), in 2003 the total storage capacity in the United States was 8.2 billion cubic feet. 82% of this capacity was in depleted gas fields, 15% in depleted aquifers, and 3% in salt caverns. Moreover during that year, withdrawals from storage added to 3.1 billion cubic feet while injections totaled 3.3 billion cubic feet (4). It is important to note that some gas injected into underground storage becomes physically unrecoverable gas. This gas is known as base gas.

Distribution is the final step before natural gas is delivered to consumers. Local Distribution Companies transport natural gas from delivery points along the transmission system to local consumers via a low-pressure, small-diameter pipeline system. Natural gas that arrives to a city gate through the transmission system is depressurized, and filtered to remove any moisture or particulate content. In addition, Mercaptan is added to the gas to create the distinctive smell that allows leaks to be detected. Small compressors are used in the distribution system to maintain the pressure required.

When Liquefied Natural Gas (LNG) is added to the mix of natural gas, three additional lifecycle stages are created: liquefaction, tanker transport, and regasification. Figure 1 shows the total life cycle of natural gas including the LNG stages.

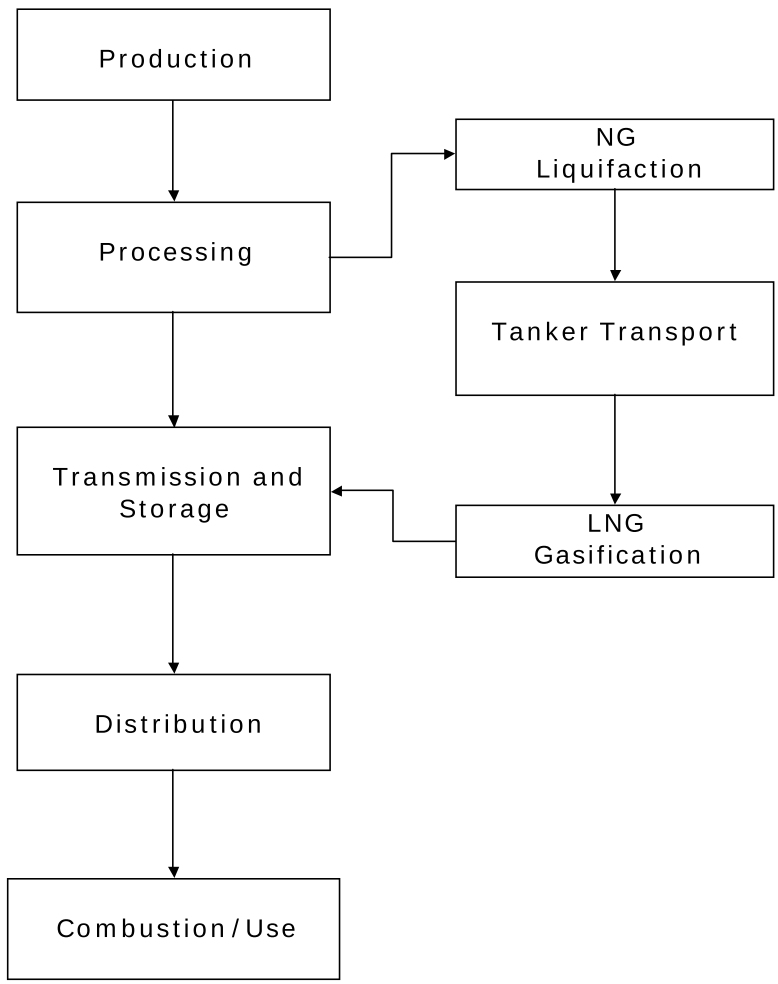

Figure 1: Natural Gas Life Cycle Including LNG.

In the liquefaction process, natural gas is cooled and pressurized to convert it to liquid form, reducing its volume by a factor of 610 (5). These liquefaction plants are generally located in coastal areas of LNG export countries. Currently 75% of the LNG imported to the US comes from Trinidad, but this percentage is expected to decrease as more imports come from Russia, the middle east, and southeast Asia (4). LNG tankers bring this gas to the US. According to EIA, there were 151 LNG tankers in operation worldwide as of October 2003. The majority of these tankers have the capacity to carry more than 120,000 cubic meters of liquefied natural gas (equivalent to 2.59 billion cubic feet of natural gas, enough gas to supply an average of 31,500 residences for a year (4)) and the total fleet capacity is 17.4 million cubic meters of liquid (equivalent to 366 billion cubic feet of natural gas). There are currently fifty-five ships under construction that will increase total fleet capacity to 25.1 million cubic meters of liquid (equivalent to 527 billion cubic feet of natural gas) in 2006 (6).

Regasification facilities are the last step LNG must pass through before going into the US pipeline system. Regasification facilities are LNG marine terminals where LNG tankers unload their gas. These facilities consist of storage tanks and vaporization equipment that warms the LNG to return it to the gaseous state. There are currently 5 LNG terminals in operation in the US: Lake Charles, Louisiana; Elba Island, Georgia; Cove Point, Maryland; Everett, Massachusetts; and a recently opened offshore terminal in the Gulf of Mexico. These terminals have a combined base load capacity of 3.05 billion cubic feet per day (about 1 trillion cubic feet per year). In addition to these there are over fifty proposed facilities for a total proposed capacity of 62 billion cubic feet per day (23 trillion cubic feet per year). Figure 2 shows the proposed location of these facilities (6).

As shown in Figure 1, natural gas combustion is the last stage in the natural gas lifecycle. In the US, natural gas is used for electricity generation, heating, and several industrial processes. Approximately 24% of the electricity generated comes from natural gas (1). Natural gas plants have heat rates that range from 5,800 BTU/kWh to 12,300 BTU/kWh (7).

US Natural Gas Industry in 2003

In 2003, the total supply of natural gas in the US was over 27 trillion cubic feet. Of this, 26.5 trillion cubic feet were produced in North America (US, Canada, and Mexico), and 0.5 trillion cubic feet were imported in the form of LNG. 75% of LNG came from Trinidad and Tobago. Other exporting countries included Algeria, Malaysia, Nigeria, Qatar, and Oman (4). Table 1 shows more detailed statistics about the state of the US natural gas industry in 2003. Numbers may not add up due to rounding.

Table 1: 2003 Natural Gas Industry Statistics (All units in million cubic feet) (4)

Gross Withdrawals	24,000,000
Total Dry Production	19,000,000
Total Supply	27,000,000
Total Consumption	22,500,000
Total Imports	4,000,000
Pipeline Imports	3,500,000
LNG Imports	505,000

Greenhouse gas emissions from Natural Gas produced in North America

During the late 1980's and early 1990's the US Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry. This very comprehensive study developed hundreds of activity and emissions factors from all the areas of the natural industry. These factors were developed using data collected from the different sectors of the industry as well as from data collected in field measurements. Table 2 presents the percentage of produced natural gas that is emitted to the atmosphere during the lifecycle according to the results of the previously described study, as well as the source of these emissions.

Table 2: Methane Emissions from North American Gas Life Cycle as a Percentage of Natural Gas Produced (8).

Lifecycle Segment	Emission Sources	Emissions as a Percentage of Gas Produced
Production	Pneumatic Devices	0.38%
	Fugitive Emissions	
	Underground Pipeline Leaks	
	Blow and Purge	
	Compressor	
	Glycol Dehydrator	
Processing	Fugitive Emissions	0.16%
	Compressor	
	Blow and Purge	
Transmission and Storage	Fugitive Emissions	0.53%
	Blow and Purge	
	Pneumatic Devices	
	Compressor	
Distribution	Underground Pipeline Leaks	0.35%
	Meter and Pressure Stations	
	Costumer Meter	

Based on the statistics presented in Table 1, 26.5 billion cubic feet of natural gas were produced in North America in 2003. Using the percentages of natural gas emitted, an average heat content of 1,030 BTU/ft^3, and the assumption that 100% of the natural gas lost is methane (density 19.23 gr/ ft^3) which may result in a slight overestimate of emissions given that the real percentage of methane in natural gas varies between 94% and 98%; total methane emission were calculated to develop the emission factors shown in Figure 4.

In addition to methane, carbon dioxide emissions are produced from the combustion of natural gas used during the lifecycle stages previously described. The Energy Information Administration maintains records of the amount of natural gas used during the production, processing, transmission, storage, and distribution of natural gas. This data for 2003 can be seen in Table 3. Assuming that 100% of this gas is methane, total carbon dioxide emissions were found using thermodynamic calculations. These emissions were then added to methane emissions to obtain the total emission factors shown in Figure 3.

Table 3: Natural Gas Used During Natural Gas Life Cycle. (All units in million cubic feet) (4).

Flared Gas	98,000
Lease Fuel	760,000
Pipeline and Distribution Use	665,000
Plant Fuel	365,000

In 1993 the Natural Gas STAR program was established by the EPA to reduce methane emissions from the natural gas industry. The program is a voluntary partnership with the goal of encouraging industries to adopt practices that increase efficiency and reduce emissions. Since 1993, 338 billion cubic feet of methane have been eliminated. In 2003, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (9). This data was used to develop a range of emission factors for the North American natural gas industry. Figure 2 shows the total range of emission factors for the North American natural gas lifecycle. It can be seen that total lifecycle emission for natural gas produced in North America are approximately 140 lbs CO_2/MMBTU, an amount dominated by combustion emissions for natural gas plants currently in operation in the US of an average 120 lbs CO_2/MMBTU (10)

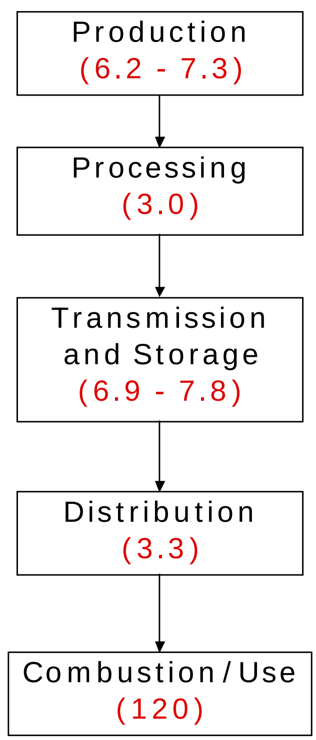

Figure 2: Carbon Dioxide Equivalent Emission Factors from North American Gas Lifecycle (All Units in lbs CO_2/MMBTU).

Greenhouse gas emissions from LNG lifecycle

As shown in Figure 1, the addition of liquefied natural gas (LNG) into the North American gas system introduces three additional stages into the lifecycle of natural gas: liquefaction, tanker transport, and regasification. It is assumed that natural gas produced in other countries and imported to the US in the form of LNG produces the same emissions in the production, processing, transmission, and distribution stages of the lifecycle as if the natural gas were produced in North America. Additional emission factors needed to be developed for the three additional lifecycle stages of LNG. Tamura et-al (11) has reported emission factors for the liquefaction stage in the range of 1.32 to 3,67 gr-C/MJ. Using these results, the emission factors for liquefaction were found in units of pounds of CO_2 per million BTUs, as shown in Table 4.

Table 4: Liquefaction Emission Factors.

Liquefaction	Emission Factors (lb CO_2/MMBTU)		
	Min	**Average**	**Max**
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Emissions from tanker transport of LNG were calculated using Equation 1.

$$EmissionFactor = \frac{(EF)\sum_{x}\left[\left(2 \times roundup\left(\frac{LNG_x}{TC}\right)\right) \times \frac{D_x}{TS} \times FC \times \frac{1}{24}\right]}{LNG_T}$$

Equation 1: Tanker Emission Factor.

Where EF is the tanker emission factor of 3,200 kg CO_2/ ton of fuel consumed; 2 is the number of trips each tanker does for every load (one bringing the LNG and one going back empty); LNG_x is the amount of natural gas (in cubic feet) brought from each country; TC is the tanker capacity in cubic feet of natural gas, assumed to be 120,000 cubic meters of LNG (1 m^3 LNG = 21,537 ft^3 NG); Dx is the distance from each country to US LNG facilities; TS is the tanker speed of 14 Knots; FC is a fuel consumption of 41 tons of fuel per day; and 24 is hours per day (12).

Exporting countries, their distances to the LNG facilities at Lake Charles, LA and Everett, MA, and the 2003 US imports can be seen in Table 5.

Table 5: LNG Exporting Countries in 2003 (4).

Exporting Country	Distance to Lake Charles Facility (nautical miles)	Distance to Everett, MA Facility (nautical miles)	2003 US Imports (million cubic feet NG)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

Emission factors for tanker transport from each country to both US facilities can be seen in Figure 3.

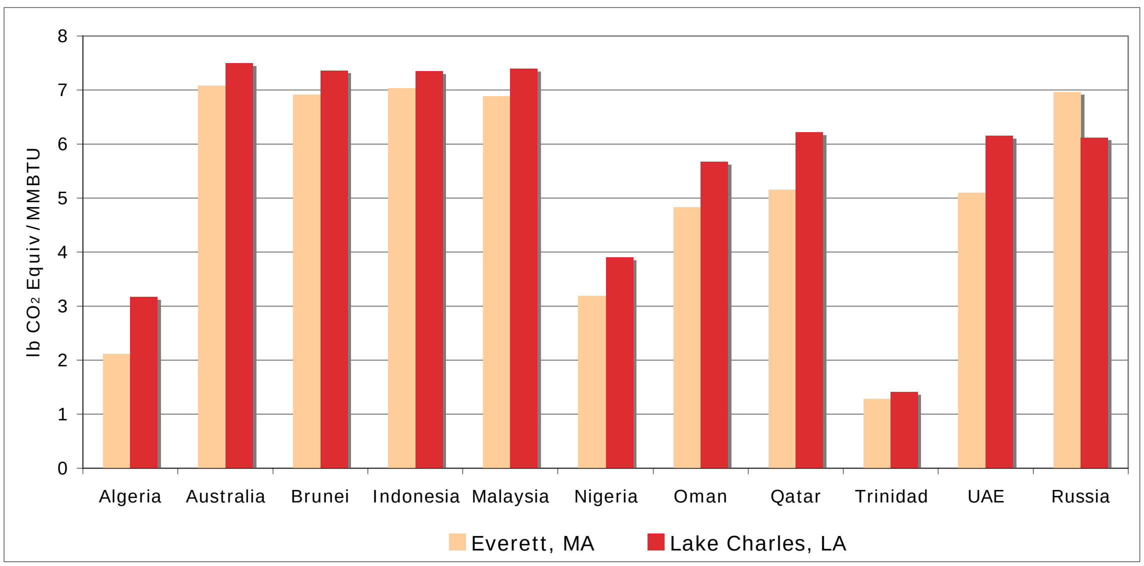

Figure 3: Tanker Emission Factors from Each Country

Since most of the LNG in 2003 was brought from Trinidad, the weighted average emission factor calculated for trips from each country to the Everett, MA facility is considered to be the a lower bound. An upper bound was obtained by assuming that all LNG was brought from Indonesia to the Lake Charles facility, and an average was obtained assuming all LNG was brought from Oman to the Lake Charles, LA facility. These resulting numbers can be seen in Table 6.

Table 6: Tanker Transport Emission Factors.

Emission Factors (lb CO_2/MMBTU)	
Min	1.8
Average	5.7
Max	7.3

Regasification emissions were reported by Tamura et-al to be 0.1 gr C/ MJ (0.85 lb CO_2/MMBTU) (11). Ruether et-al reports an emission factor of 1.6 gr CO_2/MJ (3.75 lb CO_2/MMBTU) for this stage of the LNG lifecycle by assuming that 3% of the gas is used to run the regasification equipment (13). These values were used as the lower and upper bounds of the range of emission from regasification of LNG. Total LNG lifecycle emissions are shown in Figure 4. They range between 154 and 184 lbs CO_2/MMBTU

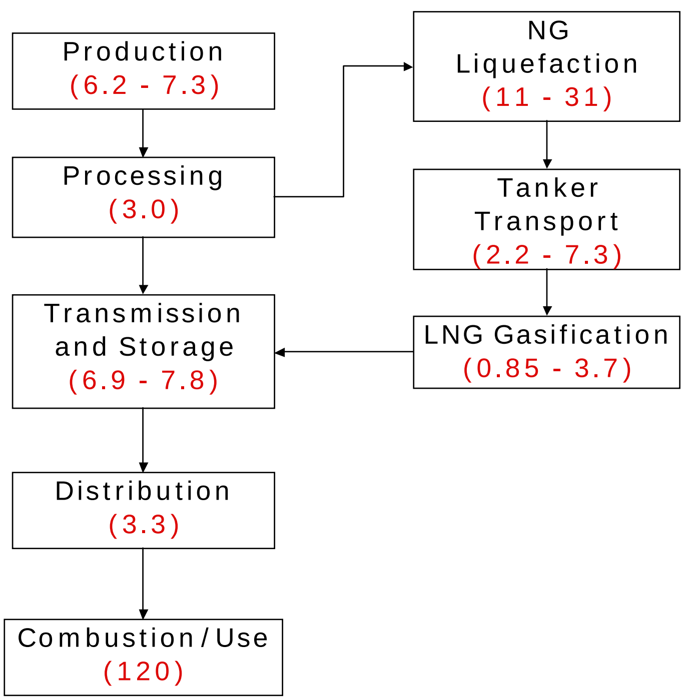

Figure 4: LNG Lifecycle Emission Factors (All Units in lbs CO_2/MMBTU).

Coal Lifecycle and its Greenhouse Gas Emissions for Electricity Generation

The coal lifecycle is conceptually simpler than the natural gas lifecycle, consisting of only three steps, as shown in Figure 5.

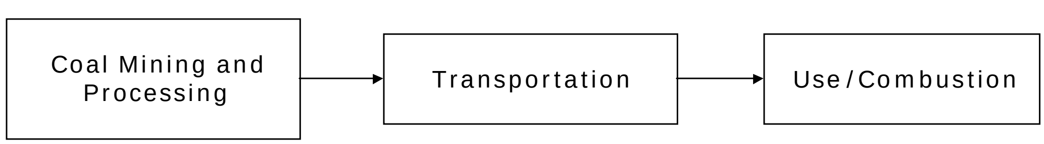

Figure 5: Coal Lifecycle.

In the US, 67% of the coal produced is mined in surface mines, while the remaining 33% is extracted from underground mines (1). Mined coal is then processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (14). Emissions from these lifecycle steps were calculated using the EIO-LCA tool developed at Carnegie Mellon University. In order to use this tool, economic values for each step of the lifecycle were necessary. In 1997, the year for which the EIO-LCA tool has data, the price of coal was $18.14/ton (15). Moreover, the cost for rail transport, barge, and truck transport was $11.06/ton, $3.2/ton, and $5.47/ton respectively (14). For a million tons of coal the following emission information was obtained using EIO-LCA.

Table 7: EIO-LCA Emission Data for Coal Lifecycle (16).

Sector	Total GHG Emissions (MT CO_2 Equiv)
Mining	75,000
Rail Transportation	36,000
Water Transportation	3,700
Truck Transportation	5,000

Using a weighted average US coal heat content of 10,266 BTU/lb (17) and the data previously discussed, it was found that the average emission factor for coal mining and transport is 11 lb CO_2/MMBTU.

In 1999, the National Renewable Energy Lab published a report on lifecycle emissions for power generation from coal (18). Upstream coal emissions (including transportation) from underground mines are reported to be 15 lbs CO_2/MMBTU, while upstream coal emissions from surface mines is 9.9 lbs CO_2/MMBTU. As previously mentioned, 67% of coal is currently mines in surface mines, while 33% is mined in underground mines (1). Using this information, the current coal upstream emissions average 12 lbs CO_2/MMBTU, which is very close to the emission factor obtained using EIO-LCA. In the future, the distribution of US mines could change, affecting the average emission factor. For this reason, the range of coal upstream emissions from underground and surface mines described above is used for this paper. Moreover, the average emission factors for coal combustion at utility plants used is 205 lb CO_2/MMBTU (10).

Comparing Natural Gas and Coal Lifecycle Emissions

Emissions factors for the natural gas lifecycle and the coal lifecycle were previously reported in pounds of CO_2 per MMBTU of fuel. Coal and natural gas power plants have different efficiencies; thus one million BTU of coal does not generate the same amount of electricity as one million BTU of natural gas. For this reason, emission factors must be converted to units of pounds of CO_2 per kWh of electricity generated. This conversion was done using the heat rates of natural gas and coal plants. Figure 6 shows the distribution of these heat rates, and Figure 7 shows the resulting emission factor distribution for coal and natural gas. These distributions were obtained using the cumulative distribution function of EIA electricity generation data for all utility plants in 2003 (7). The minimum value represents the heat rate at which 5% of the electricity generated with the specific fuel is seen. Similarly the mean and maximum values are the heat rates at which 50% and 95% of the electricity has been generated with each fuel. As seen in Figure 6, the average heat rate for natural gas plants is lower than the average heat rate for coal plants, however the upper range of heat rates for natural gas plants surpasses the heat rates for coal plants.

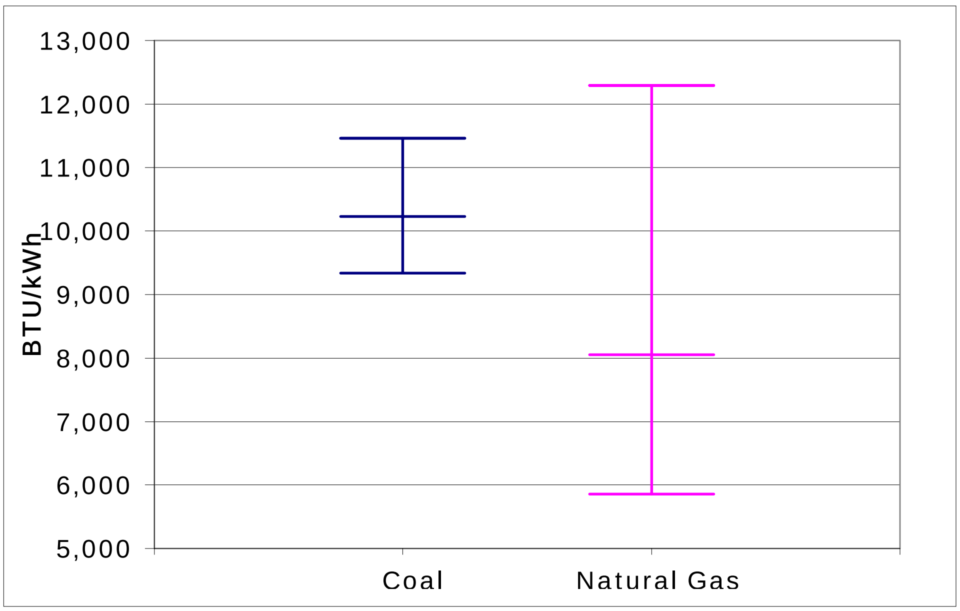

Figure 6: Natural Gas and Coal Plant Heat Rates (7).

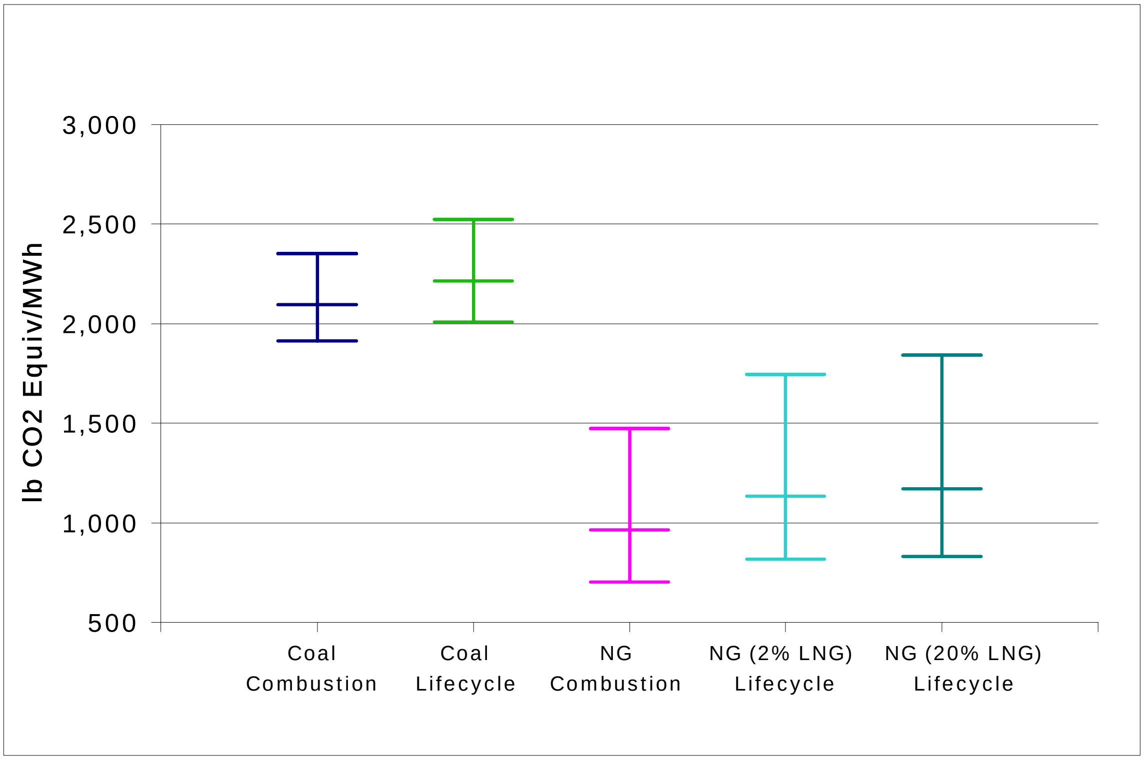

Figure 7: Emission Factors for Coal and Natural Gas Lifecycles.

Note that the average emission factor for coal combustion is higher than the emission factor for natural gas combustion. This does not change too much when the whole lifecycle is considered. More important seems to be the effect that including upstream emissions have in the range of emission factors for natural gas. While the average emission factor for the total coal lifecycle only increases by 5% compared to combustion emissions, the average emission factor for a natural gas mix with 20% LNG is 21% higher than the combustion emissions. Moreover, the maximum emission factor of the natural gas lifecycle gets closer to the minimum coal lifecycle emission factor. These results imply that if emissions at the combustion stage of the lifecycle could be controlled, natural gas would not be a much better alternative to coal in terms of greenhouse gas emissions.

New Generation Capacity

According to the DOE, by 2025 43 GW of inefficient gas and oil fired facilities will be retired, while 281 GW of new capacity will be installed (3). IGGC and NGCC power plants will probably be installed. These plants are generally more efficient than current technologies (average HHV Efficiencies are 37.5% and 50.2% respectively) (19) and thus have lower carbon emissions at the combustion stage. In addition, carbon capture and sequestration (CCS) can be performed more easily with these newer technologies. CCS is a process by which carbon emissions at the power plant are separated from other combustion products, captured and injected into underground geologic formations such as saline formations and depleted oil/gas fields. Experts believe that 90% CCS will be technologically and economically feasible in the future. Having CCS at IGCC and NGCC plants decreases the efficiency of the plants to average HHV efficiencies of 32.4% and 42.8% respectively (19) but overall lifecycle emissions would be greatly reduced and would be essentially the same for coal and natural gas (with 20% LNG). However, the major contributor for coal emissions would be at the combustion stage, while for natural gas the majority of the emissions would come from upstream processes. Figure 8, shows total emissions with CCS for IGCC and NGCC plants using average upstream emission factors of 11.6 lbs CO_2 Equiv/MMBTU and 25.6 lbs CO_2 Equiv/MMBTU for coal and natural gas respectively

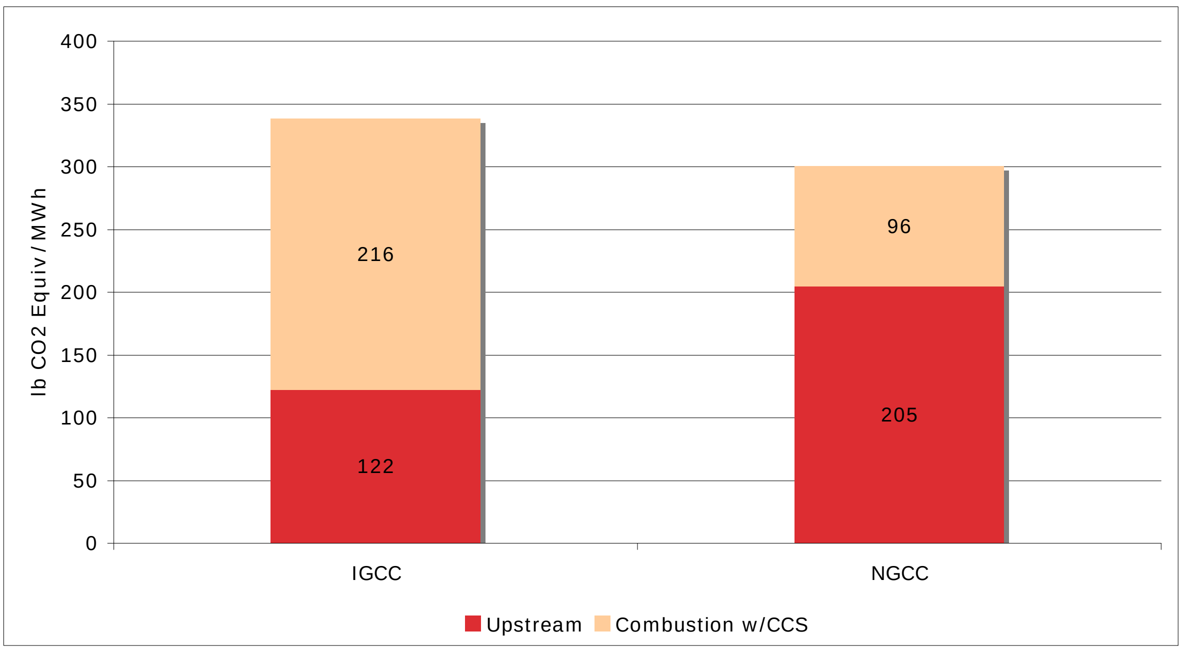

Figure 8: Lifecycle Emission Factors for IGCC and NGCC plants w/ CCS.

Discussion

It has been shown that there is high uncertainty about overall lifecycle carbon emissions for coal and LNG. In the future, as newer generation technologies and CCS are installed, overall emissions from electricity generated with coal and electricity generated with natural gas could be surprisingly similar. There is push right now from power generator to increase import of LNG. They seem to hope that the price of natural gas will decrease with these imports and they will be able to recover the investment they made in natural gas plants that are currently producing under capacity. These investments should be considered sunk costs and it is important to revaluate whether investing billions of dollars in LNG infrastructure will lead us into an energy path that cannot be easily changed as it will be harder to consider these investments as sunk costs once the expected environmental benefits are not achieved.

The analysis presented here only includes carbon emission, and no consideration was given to issues like energy security. Increasingly, LNG will come from areas of the world that are politically unstable. Policymakers should evaluate this increased dependence on foreign fuel before making decisions about future energy investments. In addition, the analysis presented only considers the use of natural gas for electricity generation. Natural gas is an indispensable fuel for many sectors of the US economy. As demand for natural gas from the electric utilities increases, these other sectors will probably be affected by higher natural gas prices. It is important to analyze whether these other sectors constitute a better use for natural gas than electricity generation, which has alternative fuels at its disposal.

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TESTIMONY OF JAMES BRADBURY

SENIOR ASSOCIATE, CLIMATE AND ENERGY PROGRAM
WORLD RESOURCES INSTITUTE

HEARING BEFORE THE U.S. HOUSE OF REPRESENTATIVES ENERGY AND COMMERCE SUBCOMMITTEE ON ENERGY AND POWER:
"U.S. ENERGY ABUNDANCE:
EXPORTS AND THE CHANGING GLOBAL ENERGY LANDSCAPE"

May 7, 2013

Summary of Key Points:

Liquefied natural gas (LNG) exports present both opportunities and risks. Producing and delivering natural gas to customers is highly energy- and emissions-intensive, particularly when LNG is involved. Research by the World Resources Institute has found that cuts in upstream methane leakage from natural gas systems are among the most important steps the U.S. can take toward meeting our greenhouse gas (GHG) emissions reduction goals by 2020 and beyond.

This testimony focuses on fugitive methane emissions and the many cost-effective solutions available for reducing them. It appears very likely that LNG exports from U.S. terminals would result in increased domestic GHG emissions from both upstream and downstream sources. Policymakers should more actively work to help achieve reductions in GHG emissions from throughout the natural gas value chain, if this valuable fuel and LNG are to be part of the solution to the climate change problem. Taking these actions offer economic, environmental, and geopolitical benefits, both in the U.S. and internationally. To this end, I offer the following policy recommendations:

- Expand applied technology research programs at the U.S. Department of Energy to help reduce the cost of leak-detection and emissions measurement technologies, and to develop new and lower-cost emission reduction strategies.
- Update emissions factors for natural gas systems using robust measurement protocols, public reporting by industry, and independent verification.
- Authorize and appropriate funding for the organization STRONGER (State Review of Oil and Natural Gas Environmental Regulations) to help states with timely development and evaluation of their environmental regulations.
- Support voluntary programs at the U.S. Environmental Protection Agency (EPA), including Natural Gas STAR and other programs which recognize companies that demonstrate a commitment to best practices.
- Support EPA's efforts to provide technical and regulatory assistance to states with expanding oil and natural gas development, including through the Ozone Advance Program.
- Enact policies to support clean energy and address climate change. A clean energy standard or putting a price on carbon would provide clear signals to energy markets that energy providers and users need to recognize the environmental and social costs as well as the direct economic costs of energy resources.

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"U.S. ENERGY ABUNDANCE:
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May 7, 2013

Good morning, and thank you for the opportunity to contribute to the deliberations of this Subcommittee. My name is James Bradbury, and I am a senior associate in the Climate and Energy Program at the World Resources Institute (WRI). WRI is a non-profit, non-partisan think tank that focuses on the intersection of the environment and socio-economic development. We go beyond research to put ideas into action, working globally with governments, business, and civil society to build transformative solutions that protect the earth and improve people's lives. We operate globally because today's problems know no boundaries. We provide innovative paths to a sustainable planet through work that is accurate, fair, and independent.

Summary

I am pleased to be here today to offer WRI's perspective on the climate implications of U.S. liquefied natural gas (LNG) exports. I encourage this committee to weigh a complete consideration of the associated economic and geopolitical opportunities next to the potential risks, neither of which have been fully considered in the public debate. In particular, it appears very likely that LNG exports from U.S. terminals would result in increased domestic greenhouse

gas (GHG) emissions. For example, analysis by the Energy Information Administration (EIA)[1] concluded that any scenario of LNG exports would trigger an increase in domestic carbon dioxide (CO_2) emissions, due to an increase in coal-fired electricity and use of natural gas for the energy-intensive liquefaction process at LNG terminals. The EIA also projected an increase in natural gas production from shale wells. Though not considered in the EIA study, an inevitable consequence would be greater upstream air emissions from natural gas infrastructure – that is, emissions that occur prior to fuel combustion – including fugitive methane, which is a potent global warming pollutant. While LNG exports from the U.S. are widely expected to marginally reduce global CO_2 emissions, modeling to date suggests that the scale of these reductions is less than ten percent of the total levels of global fugitive methane emissions from natural gas and oil systems.

These facts should raise the bar for policymakers and advocates for LNG exports to more actively work to achieve continuous improvement in GHG emissions from all life cycle stages (from extraction to use), if natural gas and LNG are to be part of the solution to our climate change problem. Furthermore, to the extent that substantial LNG exports from the U.S. move forward, our national policy objectives should be broader than simply improving our balance of trade vis-à-vis fossil fuel exports to increase our economic and geopolitical standing. We also have an important – indeed urgent – opportunity to improve our economic and geopolitical standing by showing leadership in addressing global climate change. We can do through policies

[1] See: http://www.fossil.energy.gov/programs/gasregulation/reports/fe_eia_lng.pdf

that promote the development, deployment, and export of low-carbon products and services[2] to help enable global GHG emissions reductions from all sectors, including through technologies and practices that allow the cleaner production and more efficient end-use of natural gas.

Today I will focus in particular on fugitive methane emissions[3] and the cost-effective solutions available for reducing them.[4] The case for policy action is particularly strong considering that recent research shows that climate change is happening faster than expected. In addition, the projected expansion in domestic oil and natural gas production increases the risk of higher GHG emissions if proper protections are not in place.

- Methane is the primary component of natural gas and also a potent greenhouse gas. Methane leaked from natural gas systems (i.e., fugitive methane) represent lost product and reduced revenue for companies and governments, with negative consequences for air quality and the environment.
- Fugitive methane emissions from natural gas systems represent roughly 3 percent of global warming pollution in the U.S. Reductions in methane emissions are urgently needed as part of the broader effort to slow the rate of global temperature rise.
- Although natural gas burns much cleaner than coal or oil, fugitive methane emissions significantly reduce this relative advantage, from a climate standpoint; therefore, cutting

[2] For more information on low-carbon market opportunities, see Jennifer Morgan's testimony, here: http://www.wri.org/publication/testimony-american-energy-security-and-innovation-assessment-of-energy-resources

[3] While this testimony focuses on greenhouse gas emissions – and methane emissions from natural gas systems, in particular – WRI is committed to minimizing the full scope of impacts cause by energy production and use. It is critical for U.S. energy policies to be developed with consideration to a broad range of risks and benefits.

[4] For more detailed analysis and discussion of this topic, see WRI's recent working paper, "Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems." Available at: http://www.wri.org/publication/clearing-the-air

fugitive emissions from natural gas systems would ensure that the climate impacts of natural gas are much lower than coal or diesel fuel over any time horizon.

- Recent emissions standards from the U.S. Environmental Protection Agency (EPA) will substantially reduce leakage from natural gas systems, but to help slow the rate of global warming pollution and improve air quality, further action by states and federal agencies should directly address fugitive methane from new and existing wells and equipment.
- Fortunately, most strategies for reducing fugitive methane emissions are cost-effective, with payback periods of three years or less. A recent WRI report found that cuts in methane leakage from natural gas systems are among the most important steps the U.S. can take toward meeting our GHG emissions reduction goals.[5]
- The process of liquefaction, transport, and regasification of LNG is highly emissions-intensive, increasing by 15 percent the total life cycle GHG emissions associated with exported U.S. natural gas, compared to natural gas that is produced and consumed domestically. These added upstream emissions also significantly reduce the relative advantage that natural gas would have over higher-emitting fuels, like coal and oil.
- The following policy actions by Congress would help reduce methane emissions as cost-effectively and quickly as possible:
    - Expand applied technology research programs at the U.S. Department of Energy (DOE) to help reduce the cost of leak-detection and emissions measurement technologies, and to develop new and lower-cost emission reduction strategies.

[5] See: "Can the U.S. Get There from Here? Using Existing Federal Laws and State Actions to Reduce Greenhouse Gas Emissions," available at: http://www.wri.org/publication/can-us-get-there-from-here.

- Update emissions factors for natural gas systems using robust measurement protocols, public reporting by industry, and independent verification.
- Authorize and appropriate funding for the organization STRONGER (State Review of Oil and Natural Gas Environmental Regulations) to help states with timely development and evaluation of their environmental regulations.
- Support voluntary programs at EPA, including Natural Gas STAR and other programs which recognize companies that demonstrate a commitment to best practices.
- Support EPA's efforts to provide technical and regulatory assistance to states with expanding oil and natural gas development, including through the Ozone Advance Program.

- Broader action on policies supporting clean energy and addressing climate change should also be on the table. A clean energy standard or putting a price on carbon would provide clear signals to energy markets that energy providers and users need to recognize the environmental and social costs as well as the direct economic costs of energy resources.

Finally, every day that we take no policy action on climate change, we make the policy choice to let climate change run its course. This ignores the overwhelming consensus of climate scientists who have been warning for decades that rising GHG emissions will cause the planet to warm, sea levels to rise, and weather to become more extreme. It is indisputable that these climate changes are happening today, in many cases much more quickly than expected. Action is urgently needed.

LNG Exports, the Public Interest, and Climate Change

When reviewing grant applications for LNG export authorizations, DOE is required to determine if proposed exports “will not be consistent with the public interest." In making this finding, DOE is considering a range of factors, including economic, energy security, and environmental impacts.[6] The climate change implications of LNG exports touches on each of these factors and therefore deserves more careful consideration by Congress and DOE.

The January 2012 study by EIA included a useful but limited assessment of the climate change implications of LNG exports, while the NERA Economic Consulting report (December 2012) was more narrowly focused on macroeconomic considerations.[7] This testimony focuses particular attention to how LNG exports – and increased production of natural gas more broadly – could affect domestic and international GHG emissions, which is clearly a question of relevance to the public interest.

There is no doubt that our climate is already changing in ways that are increasingly risky, difficult to manage, and harmful to public health and the environment.[8] Recent science assessments – including by the U.S. National Academy of Sciences and the U.S. Global Change Research Program[9] – agree that GHG emissions are very likely causing higher global temperatures, rising sea levels, and more frequent extreme weather events. National science

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[6] See: http://www.fossil.energy.gov/programs/gasregulation/LNGStudy.html

[7] Both reports are available here: http://www.fossil.energy.gov/programs/gasregulation/LNGStudy.html

[8] National Academies, Committee on Climate Choices, Final Report, 2011. http://dels.nas.edu/Report/America-Climate-Choices-2011/12781

[9] http://ncadac.globalchange.gov/download/NCAJan11-2013-publicreviewdraft-fulldraft.pdf

academies from over a dozen countries, including the U.S., have expressly urged governments to take urgent action to curb these harmful emissions.[10]

The current U.S. commitment to the international community is to reduce GHG emissions below 2005 levels by 17 percent in 2020 and 83 percent in 2050.[11] While a shift in electric generation to natural gas from coal has played a significant role in recent reductions in U.S. carbon dioxide emissions, this market-driven trend in the power sector has reversed somewhat in recent months, as natural gas prices have been increasing.[12] Furthermore, GHG emissions from all major sources will need to be addressed for the U.S. to help achieve climate stabilization at 2° Celsius, which the international community has agreed to be an appropriate and relatively safe target. A recent report by the World Bank[13] found that the world is on track for at least a 4° Celsius increase in global temperatures, which would be extremely damaging to global development goals and be "marked by extreme heat-waves, declining global food stocks, loss of ecosystems and biodiversity, and life-threatening sea level rise." However, the World Bank also concluded that there is still time to enact policies that would help avoid this outcome.

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[10] G8+5 Academies' joint statement: Climate change and the transformation of energy technologies for a low carbon future. http://www.nationalacademies.org/includes/G8+5energy-climate09.pdf

[11] See: http://unfccc.int/files/meetings/cop_15/copenhagen_accord/application/pdf/unitedstatescphaccord_app.1.pdf

[12] See: http://insights.wri.org/news/2013/03/new-data-reveals-rising-coal-use

[13] See: http://climatechange.worldbank.org/content/climate-change-report-warns-dramatically-warmer-world-century

Concerns about the environmental impacts of shale gas development

Natural gas production in the United States has increased rapidly in recent years, growing by 23 percent from 2007 to 2012.[14] This development has significantly changed projections of the future energy mix in the U.S. The shale gas phenomenon has also helped reduce energy prices, directly and indirectly supporting growth for many sectors of the U.S. economy, including manufacturing. The EIA projects that the United States will begin exporting LNG within 5 years and that the country will be a net natural gas exporter by the year 2020.[15]

Shale gas development has also triggered divisive debates over the near- and long-term environmental implications of developing and using these resources, including concerns about water resources, air quality, and land and community impacts.[16] Like all forms of energy, including conventional natural gas, there are public health and environmental risks associated with shale gas development. Chief among public concerns are drinking water contamination resulting from improper wastewater management, chemical spills, and underground methane migration into groundwater. There are also concerns regarding air emissions, and land-related impacts including habitat fragmentation and soil erosion. Other common concerns involve community impacts related to industrial development and extensive truck traffic. In 2011, the Secretary of Energy Advisory Board's Natural Gas Subcommittee warned[17] that "disciplined attention must be devoted to reducing the environmental impact" of shale gas development in the

[14] See: http://www.eia.gov/forecasts/aeo/index.cfm
[15] ibid
[16] For more detailed discussions of the broader environmental impacts of natural gas development, see: http://www.gao.gov/products/GAO-12-732; and http://www.rff.org/Documents/RFF-Rpt-PathwaystoDialogue_FullReport.pdf
[17] http://www.shalegas.energy.gov/resources/111811_final_report.pdf

face of its expected continued rapid growth, with as many as 100,000 more wells expected over the next few decades.

Of particular concern are the air emissions and climate change implications of shale gas development, including fugitive methane emissions, which reduce the net climate benefits of using lower-carbon natural gas as a substitute for coal and oil for electricity generation and transportation, respectively. Other air emissions from the natural gas sector include CO_2, volatile organic compounds (VOCs, which are chemicals that contribute to ground-level ozone and smog), and hazardous air pollutants (HAPs). In 2012, EPA finalized air pollution standards for VOCs and HAPs from the oil and natural gas sector. These rules will improve air quality and have the co-benefit of reducing methane emissions. As discussed below (see p. 18, "Progress is Being Made but There is More Work to Be Done"), these standards should be complemented by additional actions to further reduce methane emissions, which will help slow the rate of global temperature rise in the coming decades.

From the standpoint of CO_2 emissions, shale gas development and lower natural gas prices have contributed to recent emissions reductions in the U.S. However, GHG emissions are projected to rise, and market forces and voluntary actions alone will not enable an effective response to climate change. Thus broad policy action will be needed. For example, analysis by the International Energy Agency (IEA)[18] found that a significant global increase in use of natural gas over the coming decades could have some net climate benefits compared to scenarios in which oil and coal play more prominent roles. However, the IEA's "Golden Rules Case" scenario

[18] International Energy Agency, "Golden Rules for a Golden Age of Gas." Available at: http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/weo2012_goldenrulesreport.pdf

would result in CO_2 concentrations in the atmosphere of 650 parts per million (ppm) and a global temperature rise of 3.5° Celsius, almost twice the internationally accepted 2° Celsius target. Economic modeling conducted by researchers at MIT[19] and Resources for the Future[20] have also found that while greater use of natural gas may offer some climate benefits, climate and energy policies will be needed to reduce CO_2 emissions by anywhere near our 83 percent target by mid-century. While natural gas will likely play an essential bridging role in this transition, this will require both reducing the upstream GHGs produced during the extraction process, and ─ if gas-fired power plants are to be a part of a longer-term energy future ─ using carbon capture and storage (CCS) technology.

Why Focus on Methane Emissions?

Though methane accounted for only 10 percent of the U.S. greenhouse gas emissions inventory in 2010 (Figure 1),[21] it represents one of the most important opportunities for reducing GHG emissions in the U.S.[22] In addition to the scale and cost-effectiveness of the reduction opportunities, climate research scientists have concluded that cutting methane emissions in the near term could slow the rate of global temperature rise over the next several decades.[23]

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[19] See: http://globalchange.mit.edu/research/publications/2229

[20] See: http://www.rff.org/RFF/Documents/RFF-IB-09-11.pdf

[21] Note: all GHG inventory numbers referred to in this testimony were adjusted to reflect a more current global warming potential (GWP) for methane of 25 (IPCC 2007). This is necessary because when EPA converts methane to carbon dioxide equivalents they use an out-of-date GWP for methane of 21 (IPCC 1995), for the sake of consistency with UNFCCC reporting guidelines.

[22] See: "Can the U.S. Get There from Here? Using Existing Federal Laws and State Actions to Reduce Greenhouse Gas Emissions," available at: http://www.wri.org/publication/can-us-get-there-from-here.

[23] National Research Council, 2011. "Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia," ISBN: 0-309-15177-5, 298 pages. http://www.nap.edu/catalog/12877.html

Rising methane concentrations in the atmosphere have a potent, near-term warming effect because this greenhouse gas has a relatively high global warming potential and short atmospheric lifetime (IPCC 2007). Global warming potential (GWP) is a measure of the total energy that a gas absorbs over a particular period of time (usually 100 years), compared to carbon dioxide. Key factors affecting the GWP of any given gas include its average atmospheric lifetime and the ability of that molecule to trap heat. By mass, the same amount of methane emissions is 25 times more potent than carbon dioxide emissions over a 100-year time horizon (IPCC 2007). In the 20-year time frame, studies estimate that methane's GWP is at least 72 times greater than that of carbon dioxide.

Scientists at the National Research Council of the U.S. National Academy of Sciences have concluded that global CO_2 emissions need to be reduced in the coming decades by at least 80 percent to stabilize atmospheric CO_2 concentrations and thereby avoid the worst impacts of global climate change.[24] However, given the slow pace of progress in the U.S. in this regard, it is valuable and important for policymakers to consider cost-effective mitigation strategies – such as cutting methane emissions – that would have a disproportionate short-term impact.

How Emissions-Intensive is U.S. Natural Gas?

EPA estimates that total emissions from the development, transmission, and use of natural gas in the U.S. made up roughly a quarter of the total U.S. GHG inventory in 2011.[25] While natural gas emits about half as much carbon dioxide as coal at the point of combustion, the picture is more

[24] Ibid.

[25] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011 (April 2013). http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

complicated from a life cycle perspective. Three percent of the U.S. inventory is the result of fugitive methane emissions from natural gas systems[26] – i.e., natural gas lost to the atmosphere through venting and systemic leaks, prior to the point of combustion. To put this in perspective, in 2011, these methane leaks resulted in more GHG emissions[27] than all of the direct and indirect GHG emissions from U.S. iron and steel, cement, and aluminum manufacturing combined.[28]

EPA's 2013 GHG inventory implies a methane leakage rate of less than 2 percent of total natural gas production. Meanwhile, recent research[29] has shown that at less than a 3 percent leakage rate, natural gas produces fewer GHG emissions than coal over any time horizon. Additionally, reducing the methane leakage rate to below 1 percent would ensure that heavy-duty vehicles fueled by natural gas, like buses and long-haul trucks, would provide an immediate climate benefit over similar vehicles fueled by diesel. Thus, reducing total methane leakage to less than 1 percent of natural gas production is a sensible performance standard for the sector; an achievable benchmark that has not yet been reached.

Accurate estimates of the total leakage rate from the natural gas sector require reliable data for a broad range of industry activities and emissions factors associated with those activities. While EPA has recently updated industry activity data, most of the emissions factors rely on assumed emissions factors – as opposed to direct measurements, which are generally rare and often

[26] The GHG inventory estimates 6.9 million metric tons of fugitive methane from natural gas systems in 2011.
[27] This estimate is based on an assumed global warming potential for methane of 25, which is the convention when considering the climate implications of methane compared to carbon dioxide, integrated over a 100-year time frame (IPCC, 2007).
[28] See: http://www.energetics.com/resourcecenter/products/roadmaps/Pages/USManufacturingEnergyUseandGreenhouseGasEmissionsAnalysis.aspx
[29] See: http:// www.pnas.org/content/109/17/6435

outdated. Some recently published research suggests that emissions levels may be higher than EPA estimates; this, coupled with high ground-level ozone levels in Colorado and Texas and rural parts of Utah and Wyoming (i.e., smog that is attributed to shale gas production activities), suggests that the emissions problem may be worse than we think, and certainly subject to regional variations.[30]

With hundreds of thousands of wells and thousands of natural gas producers operating in the U.S., the data quality issue will likely remain an active debate, even as forthcoming data from EPA and other sources in the coming months aims to clarify these questions.[31] In its November 2011 final report, the Secretary of Energy Advisory Board recommended that natural gas companies measure and disclose air emissions from shale wells.[32] Indeed, what remains lacking is a valid system for direct measurement and independent verification of emissions data reported by this sector.[33]

Nevertheless, while uncertainties remain regarding exact methane leakage rates, the weight of evidence suggests that significant leakage occurs during every life cycle stage of U.S. natural gas systems and much more can be done to reduce these emissions cost-effectively. A recent expert

[30] Recent research based on field measurements of ambient air near natural gas well-fields in Colorado and Utah suggest that more than 4 percent of well production may be leaking into the atmosphere at some production-stage operations. For more discussion of questions regarding the quality and availability of methane emissions data, see Appendix 3 of "Clearing the Air," here: http://www.wri.org/publication/clearing-the-air.

[31] For example, independent researchers at the University of Texas at Austin are teaming up with the Environmental Defense Fund and several industry partners to directly measure methane emissions from several key sources. When results are published in 2013 and 2014, these data will provide valuable points of reference to help inform this important discussion.

[32] See: http://www.shalegas.energy.gov/

[33] Such systems and protocols have been developed for tracking emissions from other sources. For example, see: http://www.epa.gov/etv/vt-ams.html

survey by Resources for the Future[34] identified methane emissions as a "consensus environmental risk" that should be addressed through government and industry actions.

How Will LNG Exports Affect Greenhouse Gas Emissions?

To the extent that it is displacing higher-carbon fuels such as coal and oil, natural gas has the potential to help reduce total greenhouse gas emissions. This is particularly true as long as upstream emissions associated with natural gas are minimized and ideally methane leakage is kept below 1 percent of total production, as discussed above.

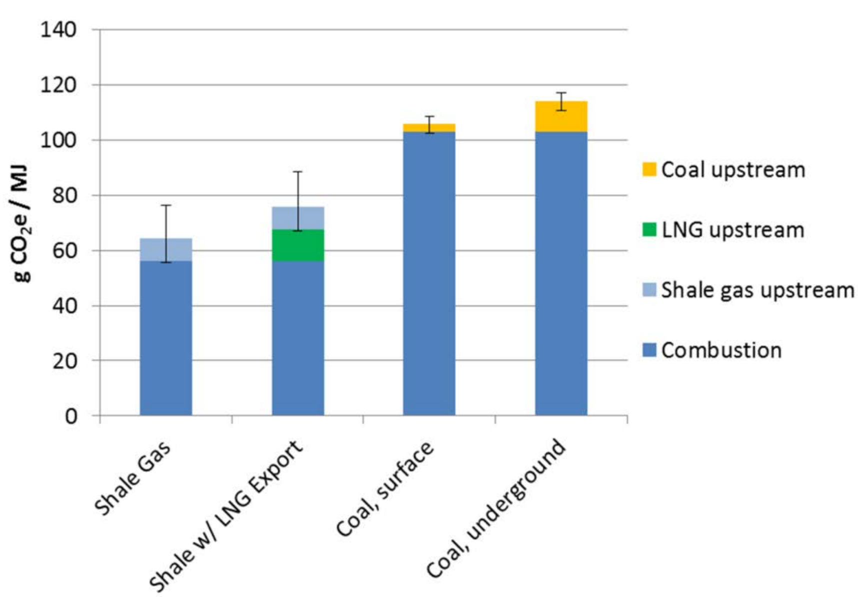
That said, the potential for LNG exports raises three primary concerns from a climate perspective.

1) The first area of concern involves upstream GHG emissions associated with increased onshore natural gas production. EIA projects that LNG exports would result in increased domestic production of natural gas, with roughly three quarters of this from shale sources. As shown in Figure 1, there are significant upstream GHG emissions (both CO_2 and methane) associated with shale gas production in the U.S. Given continued uncertainty around the actual level of methane emissions over the lifetime of both conventional and unconventional gas wells,[35] this projected market response could result in substantially higher levels of GHG emissions from throughout U.S. natural gas systems. The good news is that there are many ways to cost-effectively reduce upstream methane emissions; we encourage government and industry to do more to realize this

[34] See: http://www.rff.org/Documents/RFF-Rpt-PathwaystoDialogue_FullReport.pdf
[35] Most studies estimate that upstream GHG emissions from conventional and unconventional gas sources are roughly comparable, within the margin of error.

opportunity (see p. 20 below, “Further Potential to Reduce Fugitive Methane Emissions”).

Figure 1: Estimated Life Cycle Greenhouse Gas Emissions from U.S. Shale Gas, LNG Exports, and Coal



Sources: Bradbury et al. 2013; Weber and Clavin, 2012; NETL, 2012; Burnham et al. 2011

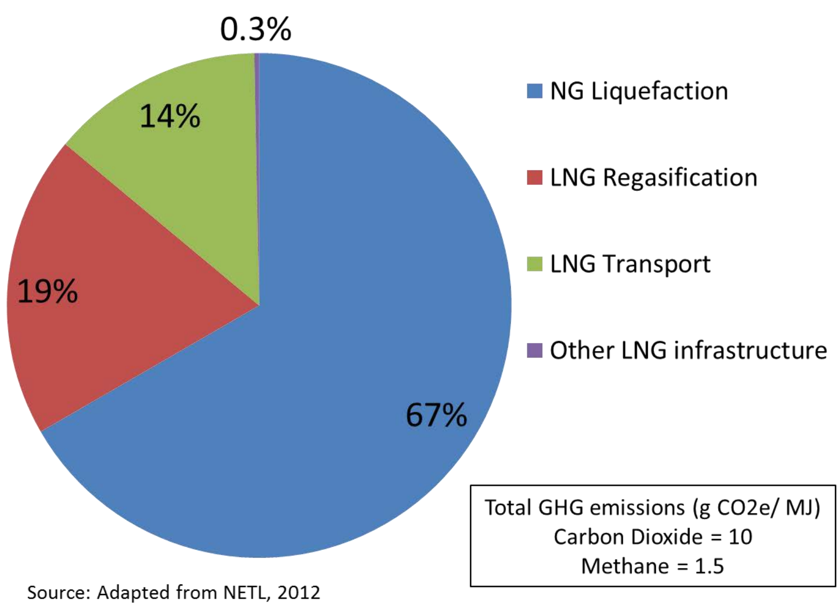
2) The second area of concern is with respect to the liquefaction, transport, and regasification of LNG exports. According to a 2012 Natural Gas Technology Assessment by the National Energy Technology Lab (NETL),[36] these energy- and emissions-intensive processes would add roughly 15 percent[37] to total life cycle GHG emissions associated with U.S. onshore natural gas production (see Figure 1, above, “LNG upstream”). These added upstream emissions significantly reduce the relative advantage that natural gas

[36] NETL (National Energy Technology Laboratory). 2012. Role of Alternative Energy Sources: Natural Gas Technology Assessment. National Energy Technology Laboratory, U.S. Department of Energy. Available at: http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=435

[37] Based on data provided in Appendix B of the NETL (2012) report, we calculate 11.5 grams of CO_2 equivalent per megajoule (g CO2e/MJ) of natural gas exported, which we added to estimated life cycle emissions associated with shale gas production, after the recent EPA rule takes effect (8.25 g CO2e/MJ), and typical estimate of final combustion of natural gas (56 g CO2e/MJ).

would have over higher-emitting fuels like coal.[38] The chart below illustrates the relative contributions of each process to total GHGs associated with LNG exports; liquefaction is the most emissions-intensive process, followed by regasification and transport. It is also worth noting that natural gas liquefaction emissions would occur at domestic LNG terminals, adding to total U.S. GHG emissions.

Figure 2: Life Cycle GHG Emissions from LNG Terminals, Transport, and Infrastructure



3) The third area of concern is the indirect domestic and international energy market implications of U.S. LNG exports. EIA's 2012 report to DOE found that LNG exports would raise domestic prices for natural gas, making natural gas relatively less competitive compared to other energy sources in the U.S., resulting in greater use of coal

[38] Note that the data presented in Figure 1 show life cycle emissions estimates for the domestic production of natural gas and coal, with upstream LNG numbers assuming LNG exported from Trinidad and Tobago and imported in Louisiana. Ideally, this figure would offer a direct comparison between life cycle emissions from domestic shale gas production and export versus coal or fuel oil in the country of import. However, such data are not readily available at this time.

and higher levels of GHG emissions under all LNG export scenarios.[39] The global GHG implications of LNG exports from the U.S. is harder to assess, but the basic picture is that more gas would be sold into international markets, which would help reduce carbon dioxide emissions as long as it displaced higher-carbon fuel sources. Given the extensive scale of planned coal-fired power plants around the world[40] and accounting for the prevalence of energy-efficient technologies available for natural gas combustion,[41] this is a reasonable assumption. On the other hand, a greater abundance of lower-priced natural gas in global energy markets (supported by U.S. LNG exports) is also expected to increase total energy use and displace some lower-carbon renewable and nuclear energy sources, which will increase GHG emissions in markets where lower-carbon technologies have become relatively cost-effective. Taking all of these factors into consideration, IEA projections[42, 43] find that greater supplies of natural gas would lead to net annual reductions in global CO_2 emissions of 0.5 percent by 2035.[44] The report concludes that "while a greater role for natural gas in the global energy mix does bring environmental benefits where it substitutes for other fossil fuels, natural gas cannot on its own provide the answer to the challenge of climate change."

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[39] The EIA estimates increases in U.S. CO_2 emissions between 9 and 75 MMt per year, from 2015 to 2035.
[40] See: http://www.wri.org/publication/global-coal-risk-assessment
[41] See: http://www.c2es.org/technology/factsheet/natural-gas
[42] See: http://www.worldenergyoutlook.org/goldenageofgas/
[43] See: http://www.worldenergyoutlook.org/media/weowebsite/2011/WEO2011_GoldenAgeofGasReport.pdf
[44] In their 2011 special report on natural gas, the IEA estimated that the GAS Scenario would lead to 35.3 gigatonnes (Gt) energy-related CO_2 emissions in 2035, with annual reduction of 160 million metric tons (MMt), in that year (compared to their "New Policies Scenario"). In their 2012 special report, the IEA reached a similar conclusion, estimating 184 MMt of annual reductions in global energy-related CO_2 emissions in 2035 with their "Golden Rules Case" (compared to a baseline), with global emissions rising to 36.8 gigatonnes (Gt) in the same year.

In summary, available evidence suggests that LNG exports from the U.S. would marginally reduce global CO_2 emissions, although the scale of these estimated GHG emissions savings is an order of magnitude lower than the total projected levels of global methane emissions from natural gas and oil systems.[45] Meanwhile, it appears very likely that LNG exports from U.S. terminals would result in increased domestic GHG emissions from both upstream and downstream sources.

These expected outcomes should raise the bar for policymakers and industry to more actively work to achieve continuous improvement in GHG emissions from all life cycle stages of natural gas development and use. Our research shows that reducing fugitive methane can be highly cost-effective – beneficial to customers and companies alike – and it is necessary if natural gas and LNG exports are to be part of the solution to our climate change problem, both in the U.S. and internationally.

Progress is Being Made but There is More Work to Be Done

Now for the good news. Increased attention to the air emissions issue has resulted in significant recent progress toward reducing air pollution from natural gas systems.

In April 2012 EPA finalized regulations for New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that primarily target

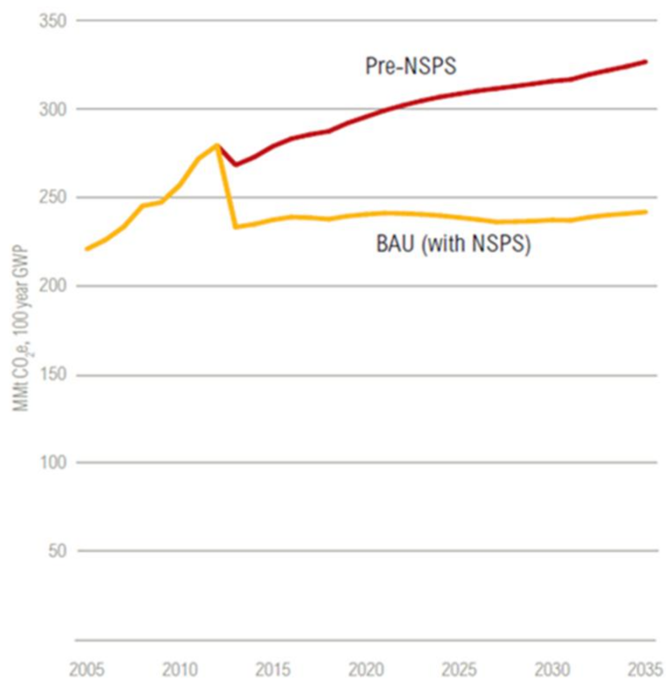
[45] By way of comparison, the EPA estimates that global annual fugitive methane emissions from natural gas and oil systems in 2030 will exceed 2,500 MMT carbon dioxide equivalent (CO_2e), assuming a GWP of 25, over a 100 year time frame (see: http://www.epa.gov/climatechange/EPAactivities/economics/nonco2projections.html). The U.S. GHG inventory estimates that fugitive methane emissions from U.S. natural gas systems in 2011 were just over 170 MMT CO2e.

VOCs and air toxics emissions but will have the co-benefit of reducing methane emissions. The new EPA rules require "green completions," which reduce emissions during the flow-back stage of all hydraulic fracturing operations at new and re-stimulated natural gas wells. The rules will also reduce leakage rates for compressors, controllers, and storage tanks.

EPA should be applauded for establishing these public health protections. Minimum federal standards for environmental performance are a necessary and appropriate framework for addressing cross-boundary pollution issues like air emissions. Federal Clean Air Act regulations are generally developed in close consultation with industry and state regulators and are often implemented by states. This framework allows adequate flexibility to enable state policy leadership and continuous improvement in environmental protection over time.

In our recent working paper, WRI estimated that these new rules will reduce methane emissions enough to cut all upstream GHG emissions from natural gas systems (including shale gas) by 13 percent in 2015 and 25 percent by 2035. As can be seen in Figure 3 below, the NSPS/NESHAP rules will make a big difference by helping to avoid a rise in upstream GHG emissions that would otherwise be likely given the projected growth in domestic natural gas production. The figure also shows that upstream carbon dioxide and methane emissions will remain a significant problem without further action.

Figure 3: Upstream GHG Emissions from All Natural Gas Systems, 2006 to 2035



Notes: Upstream GHG emissions before and after application of the EPA NSPS rule, for all natural gas systems

Source: Bradbury et al., 2013 (WRI)

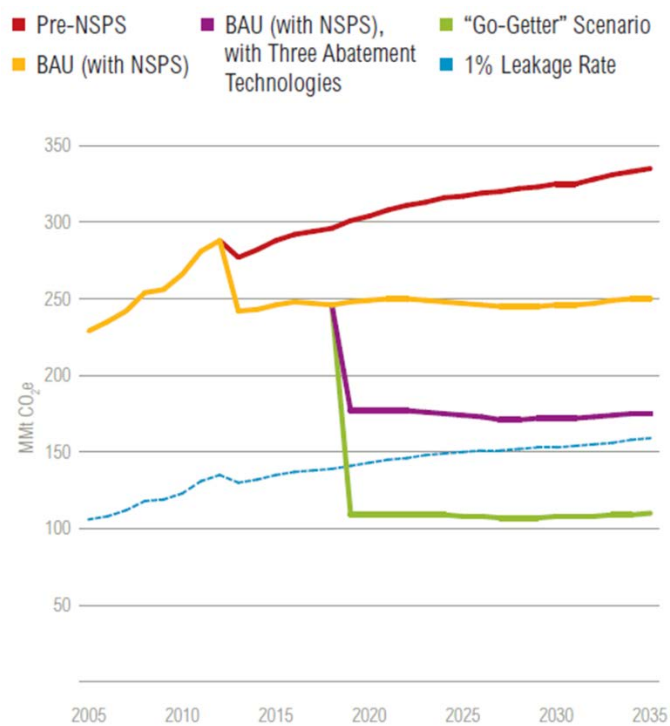
Further Potential to Reduce Fugitive Methane Emissions

WRI estimates that by implementing just three technologies that capture or avoid fugitive methane emissions, upstream methane emissions across all natural gas systems could be cost-effectively cut by up to an additional 30 percent (see Figure 4, below). The technologies include (a) fugitive methane leak monitoring and repair at new and existing well sites, processing plants, and compressor stations; (b) replacing existing high-bleed pneumatic devices with low-bleed equivalents throughout natural gas systems; and (c) use of plunger lift systems[46] at new and existing wells during liquids unloading operations. By our estimation, these three steps would

[46] Note: new data from the most recent EPA emissions inventory suggests that these technologies are much more widely used than previously thought. See: http://insights.wri.org/news/2013/05/5-reasons-why-its-still-important-reduce-fugitive-methane-emissions

bring down the total life cycle leakage rate across all natural gas systems to just above 1 percent of total production. Through adoption of five additional abatement measures that each address smaller emissions sources (i.e., a "Go-Getter" Scenario), the 1 percent goal would be readily achieved. All eight of these technologies could be implemented cost-effectively with payback periods of three years or less.

Figure 4: Upstream GHG Emissions from All Natural Gas Systems; with Additional Abatement Scenarios



Source: Bradbury et al., 2013

Policy Recommendations

New public policies will be needed to reduce methane emissions from both new and existing equipment throughout U.S. natural gas systems. WRI research has found that market conditions alone are not sufficient to compel industry to adequately or quickly adopt available best practices. To the members of this committee, I recommend the following actions to help EPA and states cost-effectively reduce air emissions from natural gas systems.

Expand applied technology research. Efforts to reduce upstream GHG emissions from natural gas systems could be aided by applied technology research at DOE. Such research should be expanded, with a focus on advancement of technologies to reduce the cost of leak detection, improve emissions measurements, and develop new and lower-cost methane emission reduction strategies.

Update emissions factors for key processes. To help resolve questions regarding the scale of methane emissions from U.S. natural gas infrastructure and operations – and to inform critical domestic and international climate and energy policy decisions – the oil and gas sector should be required to directly measure and report their emissions, with results subject to independent verification and public disclosure.

Assist with environmental regulations. With more funding, the organization STRONGER (State Review of Oil and Natural Gas Environmental Regulations) could provide more states with timely assistance in developing and evaluating environmental regulations, including (but not limited to) those designed to reduce air pollution.

Support best practices. With more funding, EPA could do more through Natural Gas STAR and other programs to recognize companies that demonstrate a commitment to best practices. This program could further encourage voluntary industry actions by maintaining a clearinghouse for technologies and practices that reduce all types of air emissions from the oil and natural gas sector.[47]

Provide technical and regulatory assistance. Recognizing the central role of state governments in achieving federal National Ambient Air Quality Standards, with more funding EPA could provide targeted technical and regulatory assistance to states with expanding oil and natural gas development. One example of a successful model that could be expanded is EPA's Ozone Advance Program. States concerned about smog and other air quality problems associated with oil and gas development voluntarily engage with this program, resulting in the co-benefit of reduced methane emissions.

Reduce carbon dioxide emissions. Broader action is also needed on policies supporting clean energy and addressing climate change. A clean energy standard or putting a price on carbon would provide clear signals to energy markets that energy providers and users need to recognize the environmental and social costs as well as the direct economic costs of energy resources.

Conclusions

Some advocate for a free-market approach to managing energy production, transmission, and use. While I agree with the general virtues of free markets, I would also caution that there is no free lunch. The National Research Council has identified very significant costs associated with

[47] An example of one existing clearinghouse can be found here: http://cfpub.epa.gov/RBLC/

fossil energy use that are hidden to most U.S. consumers.[48] Society pays when our health-care premiums rise due to harmful health effects caused by high ozone levels and other air pollution; taxpayers pick up the tab for climate change when the frequency and intensity of extreme weather events causes increasing damage to our communities and critical infrastructure.

Others highlight the energy and national security benefits of natural gas exports, which may reduce the political and economic influence of countries that do not share common interests with the U.S. and our allies. While such geopolitical benefits may be realized, LNG exports will do little to help avoid dangerous levels of climate change. We could also improve our geopolitical standing by demonstrating leadership in achieving greenhouse gas emissions reductions, much of which can be accomplished cost-effectively and with net benefits to the economy – starting with the policy actions recommended above. Meanwhile, the more we invest in fossil energy resources and infrastructure while delaying policy actions to significantly reduce GHG pollution, the more we expose ourselves and our allies to the destabilizing effects of climate change. In its 2010 Quadrennial Defense Review, the Department of Defense found that "climate change could have significant geopolitical impacts around the world." The same report concludes that climate change could further weaken fragile governments and contribute to food scarcity, spread of disease, and mass migration. Meanwhile, 30 military installations already face elevated risk from sea-level rise.

[48] NRC (National Research Council). 2010."Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use." Washington, DC: The National Academies Press. Available at: http://www.nap.edu/catalog.php?record_id=12794.

Every day that we take no policy action on climate change, we make the policy choice to let climate change run its course. This ignores the overwhelming consensus of climate scientists who have been warning for decades that rising GHG emissions will cause the planet to warm, sea levels to rise, and weather to become more extreme. It is indisputable that these climate changes are happening today, and in many cases much more quickly than expected. Action is urgently needed.

Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal

August 25, 2011

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Executive Summary

— **Research conclusion and key messages—natural gas offers greenhouse gas advantages over coal**: Natural gas has been widely discussed as a less carbon-intensive alternative to coal as a power sector fuel. In April 2011, the U.S. Environmental Protection Agency released revised methodologies for estimating fugitive methane emissions from natural gas systems. These revisions mostly affected the production component of the natural gas value chain (namely, gas well cleanups), causing a very substantial increase in the methane emissions estimate from U.S. natural gas systems.[1][2] This large increase in the upstream component of the natural gas value chain caused some to question the GHG advantage of gas versus coal over the entire life-cycle from source to use. As a result of this renewed attention, while it remains unambiguous that natural gas has a lower carbon content per unit of energy than coal does, several recent bottom-up studies have questioned whether natural gas retains its greenhouse gas advantage when the entire life cycles of both fuels are considered.[3]

Particular scrutiny has focused on shale formations, which are the United States' fastest growing marginal supply source of natural gas. Several recent bottom-up life-cycle studies have found the production of a unit of shale gas to be more GHG-intensive than that of conventional natural gas.[4] Consequently, if the upstream emissions associated with shale gas production are not mitigated, a growing share of shale gas would increase the average life-cycle greenhouse gas footprint of the total U.S. natural gas supply.

Applying the latest emission factors from the EPA's 2011 upward revisions, our top-down life-cycle analysis

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[1] *EPA, Inventory of U.S. Greenhouse Gas Emissions And Sinks:1990 – 2009, U.S. EPA, EPA 430-R-11-005, http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, cited in Mark Fulton, et al., "Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal," 14 March 2011, available at http://www.dbcca.com/dbcca/EN/_media/Comparing_Life_Cycle_Greenhouse_Gas.pdf.*

[2] *Note: For example, the EPA's estimates of methane emissions from U.S. natural gas systems in the base year of 2008 increased 120 percent between the 2010 and 2011 versions of their Inventory of U.S. Greenhouse Gas Emissions and Sinks.*

[3] *The two approaches for an LCA study are bottom-up and top-down. A bottom-up study analyzes the emissions from an individual representative or prototype process or facility and calculates the emissions of that specific part of the value chain. It then combines each step of the value chain to compute the total lifecycle emissions from source to use. A top-down study, in contrast, looks at the total national emissions for a particular use or sector and depicts the national average life-cycle emissions for each discrete part of source to use for that sector to arrive at an aggregate estimate. Each approach has benefits and limitations. The bottom-up approach provides insights into the emissions for a particular process or fuel source, but also depicts only that specific process or source. The top-down approach represents the emissions across an entire sector but does not focus on specific processes or technologies. Some of the data sources for a top-down analysis may be built up from bottom-up sources, but the top-down analysis still yields a more general result.*

[4] *Robert W. Howarth, et al., "Methane and the greenhouse-gas footprint of natural gas from shale formations,"* Climatic Change *(2011); Timothy J. Skone, National Energy Technology Laboratory (NETL), "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States," presentation (Ithaca, NY: 12 May 2011; revised 23 May 2011); Mohan Jiang, et al., "Life cycle greenhouse gas emissions of Marcellus Shale gas,"* Environmental Research Letters *6 (3), 5 August 2011.*

(LCA)[5] finds that the EPA's new methodology increases the life-cycle emissions estimate of natural gas-fired electricity for the baseline year of 2008 by about 11 percent compared with its 2010 methodology. But even with these adjustments, we conclude that **on average, U.S. natural gas-fired electricity generation still emitted 47 percent less GHGs than coal from source to use using the IPCC's 100-year global warming potential for methane of 25**. This figure is consistent with the findings of all but one of the recent life-cycle analyses that we reviewed.

While our LCA finds that the EPA's updated estimates of methane emissions from natural gas systems do not undercut the greenhouse gas advantage of natural gas over coal, methane is nevertheless of concern as a GHG, and requires further attention. In its recent report on improving the safety of hydraulic fracturing, the U.S. Secretary of Energy's Advisory Board's Subcommittee on Shale Gas Production recommended that immediate efforts be launched to gather improved methane emissions data from shale gas operations.[6] In the meantime, methane emissions during the production, processing, transport, storage, and distribution of all forms of natural gas can be mitigated immediately using a range of existing technologies and best practices, many of which have payback times of three years or less.[7] Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas. Although the adoption of these practices has been largely voluntary to date, the EPA proposed new air quality rules in July 2011 that would require the industry to mitigate many of the methane emissions associated with natural gas development, and in particular with shale gas development.[8]

Our research methodology: This paper seeks to assess the current state of knowledge about the average greenhouse gas footprints of average coal and natural gas-fired electricity in the system today, how the growing share of natural gas production from shale formations could change this greenhouse gas footprint at the margin, and what the findings imply for policymakers, investors and the environment. In the first part of the paper, we examine recent bottom-up life-cycle analyses to provide context for our top-down analysis. These bottom-up analyses' estimation of the life-cycle GHG footprint of shale gas provides information about the potential marginal GHG impact of shale's rising share in the U.S. natural gas supply, as well as which emissions streams can be targeted for the greatest GHG mitigation. In the second part of the paper, we conduct our own top-down life-cycle analysis of GHGs from natural-gas and coal-fired electricity in 2008 using the EPA's revised 2011 estimates as well as other publically available government data. We make three key adjustments to the data sets in order to calculate a more accurate and meaningful national level inventory: we include: 1) emissions associated with net natural gas and coal imports; 2) natural gas produced as a byproduct of petroleum production, and 3) the share of natural gas that passes through distribution pipelines before reaching power plants. This top-down analysis examines the implications of the EPA's revised (2011) estimates for the current and future average greenhouse gas footprint of U.S. natural gas-fired electricity and its comparison with coal-fired electricity.

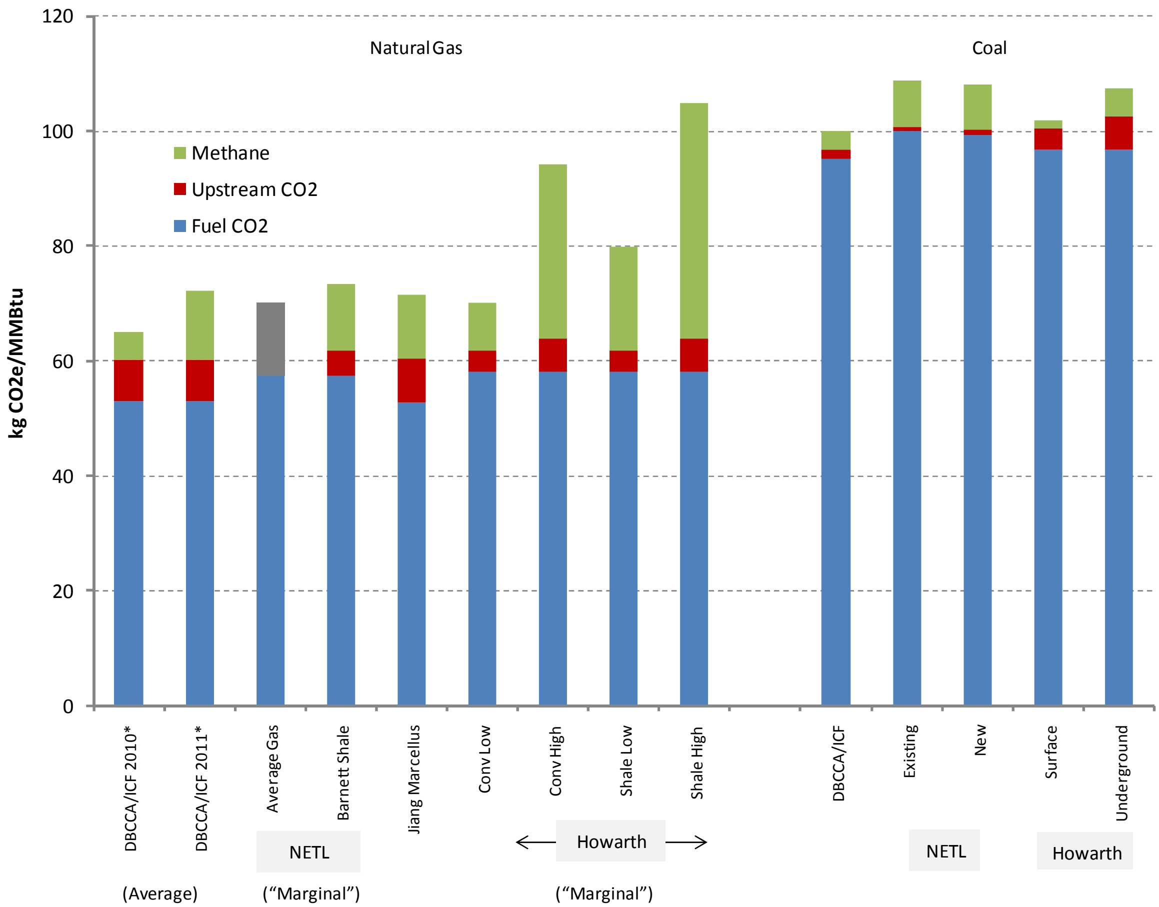
GWP and power plant efficiency matter: Global warming potentials (GWPs) are used to convert the volumes of greenhouse gases with different heat-trapping properties into units of carbon dioxide-equivalent (CO_2e) for the purpose of examining the relative climate forcing impacts of different volumes of gas over discrete time periods. The Intergovernmental Panel on Climate Change's (IPCC) most recent assessment, published in 2007, estimates methane's GWP to be 25 times greater than that of carbon dioxide over a 100-year timeframe and 72 times greater than that of carbon dioxide over a 20-year timeframe.[9] Unless

[5] "Life-cycle analysis" (LCA) is a generic term, and the methodology and scope of analysis can vary significantly across studies. Our analysis assesses GHGs during the production, processing, transport, and use of natural gas and coal to generate electricity. Some studies include not only the direct and indirect emissions from the plant or factory that provides or makes a certain product, but also the emissions associated with the inputs used to manufacture and create the production facilities themselves. This study does not address the manufacturing, construction, or decommissioning of the equipment used in energy production. As with any study, the certainty of conclusions drawn from an LCA can only be as strong as the underlying data.
[6] U.S. Department of Energy, Secretary of Energy Advisory Board, Shale Gas Production Subcommittee, 90-Day Report, 18 August 2011, http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.
[7] Numerous technologies and best practices to capture methane that would otherwise be vented during natural gas production, processing, transport, or distribution have been detailed by the U.S. EPA's voluntary Natural Gas STAR Program. Many of these have payback periods under 3 years. U.S. Environmental Protection Agency, Natural Gas STAR Program, "Recommended Technologies and Practices," available at http://www.epa.gov/gasstar/tools/recommended.html, viewed 29 July 2011.
[8] EPA, "Oil and Natural Gas Air Pollution Standards," http://epa.gov/airquality/oilandgas/, viewed 18 August 2011.
[9] Piers Forster et al., 2007: Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D.

otherwise specified, our analysis uses the 100-year GWP of 25 but we also calculate life-cycle emissions using a range of methane GWPs that have been proposed—including 72 and 105—in Appendix B of this report in order to show the sensitivities of the outputs to GWP. The choice of GWP does impact the relative GHG footprint between coal and gas. However, the life-cycle GHG footprint of gas is lower than coal under all GWPs tested, with the smallest difference calculated using a GWP of 105, where the GHG emissions in kilograms CO_2 per megawatt-hour of electricity generated (kg CO_2e/MWh) are 27 percent less than those of coal-fired generation.

In addition, assumed power plant efficiencies also have a measurable impact on the life-cycle comparison between natural gas and coal-fired electricity generation. Unless otherwise specified, our analysis uses average U.S. heat rates for coal and natural gas plants for the existing capital stock: 11,044 Btu/kWh (31% efficiency) for coal and 8,044 Btu/kWh (41% efficiency) for natural gas plants. We also calculate life-cycle emissions using heat rate estimates for new U.S. natural gas and coal plants in Appendix A (Exhibit A-11).

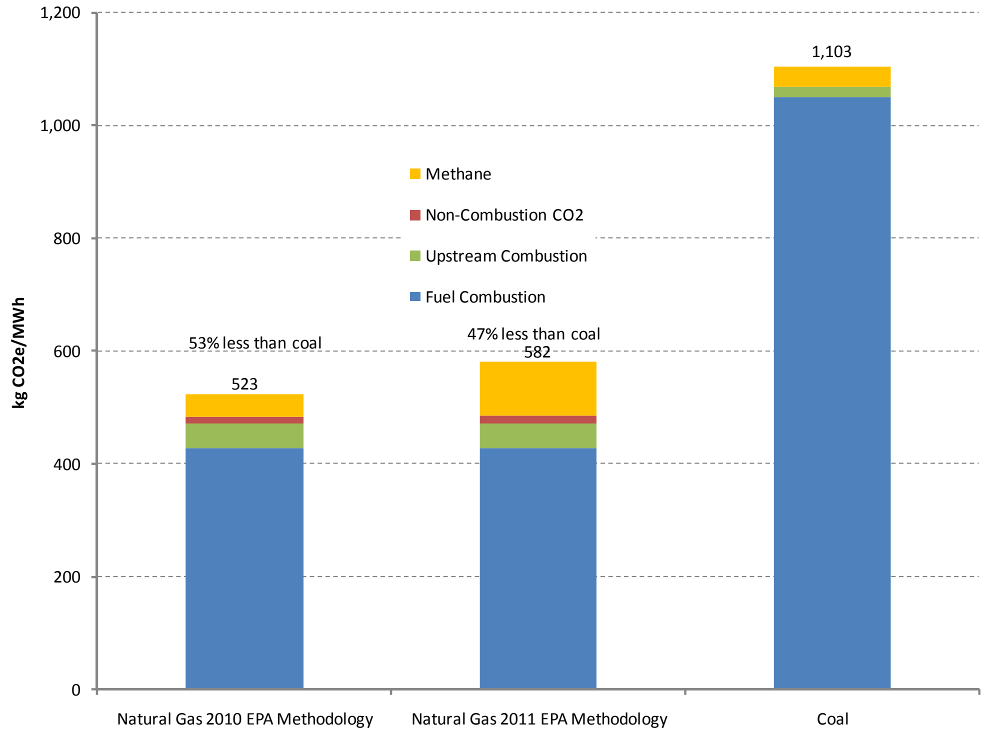
ES-1. Comparison of Recent Life-Cycle Assessments



Source: DBCCA Analysis 2011; NETL 2011; Jiang 2011; Howarth 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. See page 10 for more information. *2011 EPA methodology compared to 2010.

Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA., p. 212.

ES-2. Average U.S. Life-Cycle GHG Emissions from Coal and Gas Electricity Generation, 2008
Comparing EPA 2010 Methodology with EPA 2011 Methodology



Source: DBCCA Analysis 2011. See pages 19 and 20 for more details.

Introduction and Key Exhibits

— **Our methodology:** Our top-down analysis addresses the emissions of three GHGs emitted during the production, processing, storage, transmission, distribution, and use of natural gas and coal in power plants:

1. Carbon dioxide (CO_2);
2. Methane (CH_4) and;
3. Nitrous oxide (N_2O)

Carbon dioxide is a product of fossil fuel combustion and is also released during some stages of gas processing. Methane, the primary component of natural gas (roughly 98 percent of pipeline-quality gas), is a potent GHG.[10] It is released at many points during the life-cycle of natural gas production and use and also during coal mining, and it is an important component of the life-cycle emissions of both fuels, but especially of natural gas. Methane emissions can be categorized as "fugitive" or "vented" emissions. Fugitive emissions include unintentional "leaks" from poorly sealed valves, flanges, meters, and other equipment.[11] Venting is the intentional release of methane as part of the operating procedure for a particular process. For example, when a compressor or a pipeline is taken out of service for repair, the compressed gas in the equipment may be released. There are a variety of venting operations associated with natural gas production that account for the majority of methane emissions in the natural gas sector. Because the amount of fugitive and vented methane is highly dependent on the practices and technologies that are used, the amount of methane emitted can vary significantly by facility and/or the stripping and "clean up" process employed. Although small amounts of methane and nitrous oxide are also emitted during fossil fuel combustion, carbon dioxide is by far the largest greenhouse gas product. In this paper, because the amounts of methane and nitrous oxide are such a small fraction of the total combustion-related emissions, we include them together with CO_2 on tables and figures under the heading "combustion."[12]

— **Reader roadmap:** In the section that follows, we start with a review of recent LCA studies. These studies have attempted to measure the life-cycle GHG footprint of shale gas and are valuable from our perspective in framing the marginal impact of shale gas on the GHG intensity of average natural gas-fired electricity. We then build up to a full comparison of the life-cycle emissions between natural gas and coal-fired electricity generation at a national level based on different assumptions and data adjustments in order to assess the impact that the EPA 2011 methodology change on GHG inventory has on the LCA comparison between average U.S. natural gas- and coal-fired electricity generation. We use emissions data for 2008 as a comparable baseline to show the impact of the 2010 and 2011 changes in EPA methane methodology to the life-cycle GHG emissions comparison between coal and natural gas in that year. (Note the Global Warming Potential used throughout this analysis is 25 unless otherwise noted – see Appendix B.) This overview provides a roadmap to follow the logic of our analytic approach.

- **Step 1:** In Exhibit 2, page 10 we compare the most recent bottom-up studies of the LCA of gas from hydraulically fractured shale formations versus coal as a starting point;

- **Step 2:** In Exhibit 4, page 13 we list the baseline EPA data for 2008 on the upstream natural gas emissions expressed as million metric tons of CO_2 equivalent ($MMTCO_2e$);

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[10] Methane remains in the atmosphere for ~9-15 years, compared to 100+ years for CO_2; Methane, however, is much more effective at trapping heat in the atmosphere than CO_2, particularly over 20 year time periods (Please see Appendix B at the end of this report).

[11] Of critical importance, such leaks can be fairly easily mitigated from a technical perspective at reasonable cost, which means that there is scope for improvement.

[12] The EPA Greenhouse Gas Reporting Rule gives CH_4 and N_2O emission factors for the combustion of different fossil fuels. For CH_4, emission factors of 0.001 kg/MMBtu of natural gas and 0.011 kg/MMBtu of coal were used. For N2O, emission factors of 0.0001 kg/MMBtu of natural gas and 0.0016 kg/MMBtu of coal were used. The emission factors are in table C-2, page 38 of Subpart C of the rule. (Please see: http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-FinalRule.pdf)
These were then adjusted using GWPs for CH_4 and N_2O to obtain emissions factors in kg CO_2e/MMBtu. Unless otherwise noted in the paper, 100-year GWP values from the IPCC's Fourth Assessment Report (2007) were used: 25 for CH_4 and 298 for N_2O. Using these values, the total GHGs emitted during the combustion of natural gas are 53.07 kg CO_2e/MMBtu (99.90% CO_2, 0.05% CH_4, 0.06% N_2O) and the total GHGs emitted during the combustion of coal are 95.13 kg CO_2e/MMBtu (99.21% CO_2, 0.29% CH_4, 0.50% N_2O).

- **Step 3:** In Exhibit 5, page 14, we adjust these baseline estimates to account for additional factors such as natural gas imports, methane emissions from other parts of the industry and other types of emissions associated with natural gas production;

- **Step 4:** In Exhibit 6, page 15, we combine our adjusted upstream and downstream natural gas emissions to derive a normalized life-cycle emissions expressed as kg/MMBTU (volume of greenhouse gases per unit of energy value delivered to the power plant) and compare with coal on an equivalent carbon-dioxide equivalent basis for the electricity sector using 2008 data and the EPA's 2011 methane emissions methodology;

- **Step 5:** In Exhibit 7, page 15, we rerun Step 3 above for 2008 emissions but using the EPA 2010 methane emission methodology from the EPA in order to show the impact of the revisions pre-combustion in kg CO_2e/MMBtu;

- **Step 6:** In Exhibit 8, page 15, we use EPA's 2011 methane emissions methodology to calculate emissions for 2009, the most recent year data available;

- **Step 7:** In Exhibit 10, page 17, we adjust upstream emissions from coal into standard volume units of MMTCO_2e in order to assess the emissions associated with the production and transportation from the mine to the power plant using 2008 data for an apples-to-apples comparison with gas;

- **Step 8:** In Exhibit 11, page 17, we then normalize these upstream coal emission factors into kg CO_2e/MMBtu (emission volume per unit of energy delivered);

- **Step 9:** In Exhibit 12, page 19, we compare the life-cycle emissions of natural gas and coal delivered to the power plant in kg CO_2e/MMMBtu using 2008 data but adjusted for both 2010 and 2011 EPA methane emission factor methodologies for natural-gas to show the impact of EPA's revisions;

- **Step 10:** In Exhibit 13, page 20, we show the LCA in terms of emissions per megawatt-hour of electricity generated from gas and coal using the national average power plant efficiencies for 2008. The life-cycle emissions for gas are 11 percent higher using the updated methodology. The Exhibit shows a six percentage point change with gas producing 47 percent lower emissions than coal using EPA's 2011 methane methodology compared to producing 53 percent lower emissions using EPA 2010 methane methodology based on a 100-year GWP value for methane of 25.

- **Sensitivity Analysis Using Alternative GWPs:** In Appendix B, we show the sensitivities of our LCA to different GWPs.

Overview of Natural Gas Systems and Emission Sources

Between its 2010 and 2011 editions of the Inventory, the EPA significantly revised its methodology for estimating GHG emissions from natural gas systems, resulting in an estimate of methane emissions from Natural Gas Systems in 2008 that was 120 percent higher than its previous estimate. Up until 2010, the Inventory had relied extensively upon emission and activity factors developed in a study by the EPA and the Gas Research Institute in 1996. For the 2011 Inventory, the EPA modified its treatment of two emissions sources that had not been widely used at the time of the 1996 study, but have since become common: gas well completions and workovers with hydraulic fracturing. It also significantly modified the estimation methodology for emissions from gas well cleanups, condensate storage tanks, and centrifugal compressors.

The bulk of the EPA's recent upward revisions of natural gas emissions estimates are related to the production part of the gas value chain. The largest component of the increase is due to revised estimates of methane released from liquids unloading: In some natural gas wells, downhole gas pressure is used to blow reservoir liquids that have accumulated at the bottom of the well to the surface.[13] The revisions also include an increase in the share of gas that is produced from hydraulically fractured shale gas wells and a change in the assumption as to how much of the flow-back emissions are flared. Previously, the EPA assumed that 100 percent of these emissions were flared or captured for sale. The new estimate assumes that approximately one third are flared and another third are captured through "reduced emission completions." Both of these are based on estimated counts of equipment and facility and associated emission factors.

These revisions have caused some to question whether replacing coal with natural gas would actually reduce GHGs, when emissions over the entire life cycles of both fuels are taken into account. Addressing these questions requires an understanding of:

1) The best available data on emissions throughout the life cycles of natural gas and coal;
2) The specific sources and magnitudes of GHG emissions streams for natural gas produced from shale versus conventional formations; and
3) How an increase in the contribution of shale gas to the U.S. natural gas supply might impact the overall life-cycle GHG footprint of natural gas-fired electricity in the future as the marginal skews the average.

Up until the past few years, most of the U.S. natural gas supply came from the Gulf of Mexico and from western and southwestern states. More recently, mid-continental shale plays have been a growing source of supply. Natural gas is produced along with oil in most oil wells (as "associated gas") and also in gas wells that do not produce oil (as "non-associated gas").

Exhibit 1 illustrates the primary sources of GHG emissions during natural gas production, processing, transmission and distribution. The equipment for drilling both oil and gas wells is powered primarily by large diesel engines and also includes a variety of diesel-fueled mobile equipment. Raw natural gas is vented at various points during production and processing prior to compression and transport by pipeline. In some cases, the gas may be flared rather than vented to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Flaring produces CO_2, a less potent GHG than methane.

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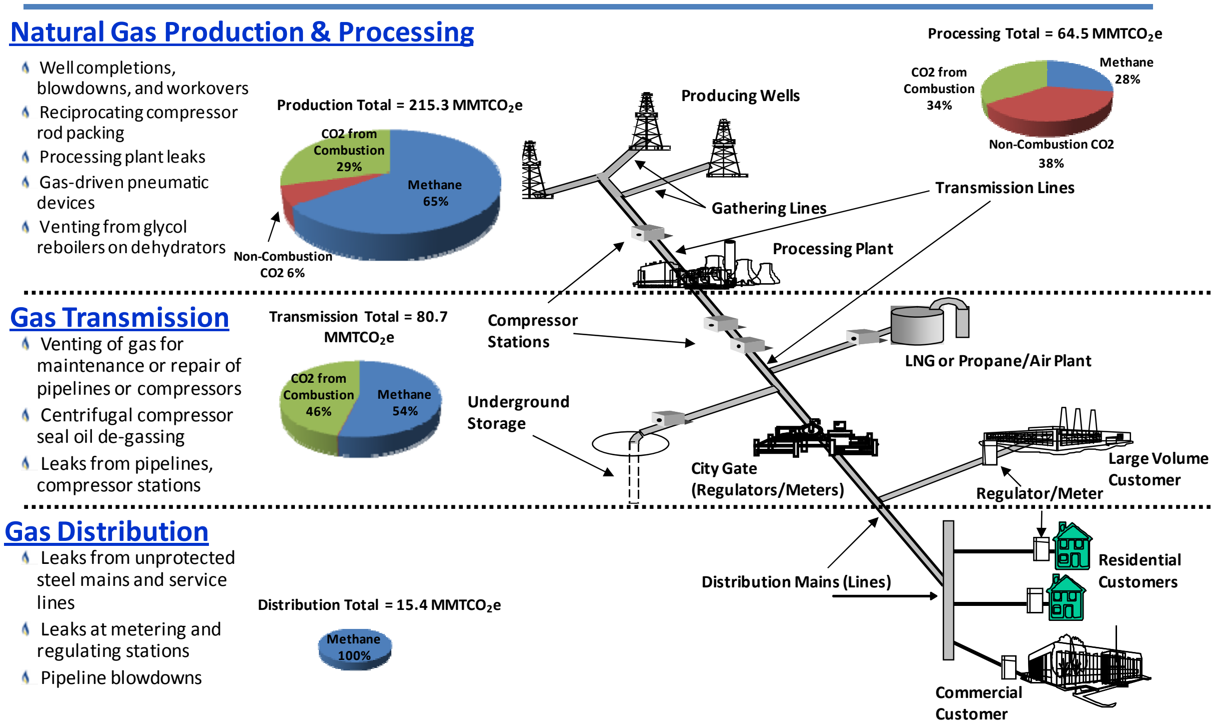
[13] The technique of blowing out liquids is most frequently used in vertical wells containing "wet" or liquids-rich gas. It is being replaced by many producers with "plunger lifts" that remove liquids with much less gas release. In many shale wells, a technique is used where liquids are allowed to collect in a side section of the well and removed with a pump. EPA, Natural GAS Star, "Lessons Learned: Installing Plunger Lift Systems in Gas Wells," October 2006, available at http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.

Exhibit 1. Natural Gas Industry Processes and Methane Emission Sources



Sources: American Gas Association; EPA Natural Gas STAR Program, DBCCA analysis, 2011.

The recent focus of new natural gas development has been shale gas, which currently represents about 14 percent of U.S. domestic production but is expected to reach 45 percent or more by 2035.[14] Most gas-bearing shale formations lie 8,000 to 12,000 feet below the surface and are tapped by drilling down from the surface and then horizontally through the target formation, with lateral drills extending anywhere from 3,000 to 10,000 feet. After drilling is complete, operators hydraulically fracture the shale, pumping fluids at high pressure into the well to stimulate the production of the gas trapped in the target rock formation. Horizontal drilling and pumping water for hydraulic fracturing release additional engine emissions compared to conventional production techniques. In addition, when the produced water "flows back" out of the well, raw gas from the producing formation can be released into the atmosphere at the wellhead.[15]

In both associated and non-associated gas production, water and hydrocarbon liquids are separated from the gas stream after it is produced at the wellhead. The gas separation process may involve some fuel combustion and can also involve some venting and/or flaring. Shale plays in particular are geologically heterogeneous, and the energy requirements to extract gas can vary widely. Moreover, the methane content of raw gas varies widely among different gas formations. Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO_2, in order for the gas to be pipeline-quality and ready to be compressed and transported. This "formation" CO_2 is vented at the gas processing plant and represents another source of GHG emissions along with the combustion emissions from the plant's processing equipment.

From the gas processing plant, natural gas is transported, generally over long distances by interstate pipeline to the "city gate" hub and then to the power plant. The vast majority of the compressors that pressurize the pipeline to move

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[14] *EIA Annual Energy Outlook 2011. DOE/EIA-0383ER(2011). Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf*

[15] *The GHG comparison between conventional and shale wells is important given the rapidly evolving industrial landscape with a share shift toward shale wells. For its part, the International Energy Agency (IEA) in a June 2011 Special Report: "Are We Entering a Global Age of Gas?" concluded that the LCA emissions of natural gas from shale wells is between 3.5 and 12 percent more than from conventional gas. IEA, June 2011, page 64.*

the gas are fueled by natural gas, although a small share is powered by electricity.[16] Compressors emit CO_2 emissions during fuel combustion and are also a source of fugitive and vented methane emissions through leaks in compressor seals, valves, and connections and through venting that occurs during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission. Actual leakage from the pipelines themselves is very small.

Some power plants receive gas directly from transmission pipelines, while others have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some relatively small methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment.

Review of Recent Bottom-Up Life-Cycle Analyses: The Marginal Impact on Emissions

The assessment of how much more methane is released from shale gas production than from conventional production is a key factor in the discussion of possible changes in the life-cycle emissions of natural gas. As the shale gas component of U.S. production increases, a higher marginal greenhouse gas footprint from shale gas would raise the average greenhouse gas footprint of the U.S. natural gas supply overall. On the other hand, changing production technology and regulation could reduce emissions from both shale and other natural gas wells. The life-cycle GHG comparison between shale and conventional natural gas therefore has important implications for stakeholders who are considering policies and investment on the basis of how carbon-intensive natural gas is today and how carbon-intensive it is likely to be in the future.

A number of recent bottom-up life-cycle analyses attempt to quantify the GHG comparison between conventional and shale gas. Exhibit 2 shows the results of several of these analyses and how they compare to our top down analysis, which follows later.[17] Bottom-up figures are taken from studies by Skone, et al. (NETL), Jiang et al. (Jiang), and Howarth, et al. (Howarth). Because these and other life-cycle studies each make different assumptions as to the global warming potential of methane and the product whose greenhouse gas footprint is being measured—some use units of natural gas produced, others use units of natural gas delivered, and still other use units of electricity generated—we have normalized these figures using a GWP of 25. Any remaining variability in the GHG estimates are the result of differences in underlying emissions factors used. Despite differences in methodology and coverage, all of the recent studies except Howarth et al. estimate that life-cycle emissions from natural gas-fired generation are significantly less than those from coal-fired generation on a per MMBtu basis. As can be seen in Exhibit 2, our GHG estimate for average U.S. gas based on EPA's 2011 data (72.3 kg/MMBtu) is very similar to the National Energy Technology Laboratory's (NETL) bottom-up estimate for Barnett Shale gas (73.5 kg/MMBtu).

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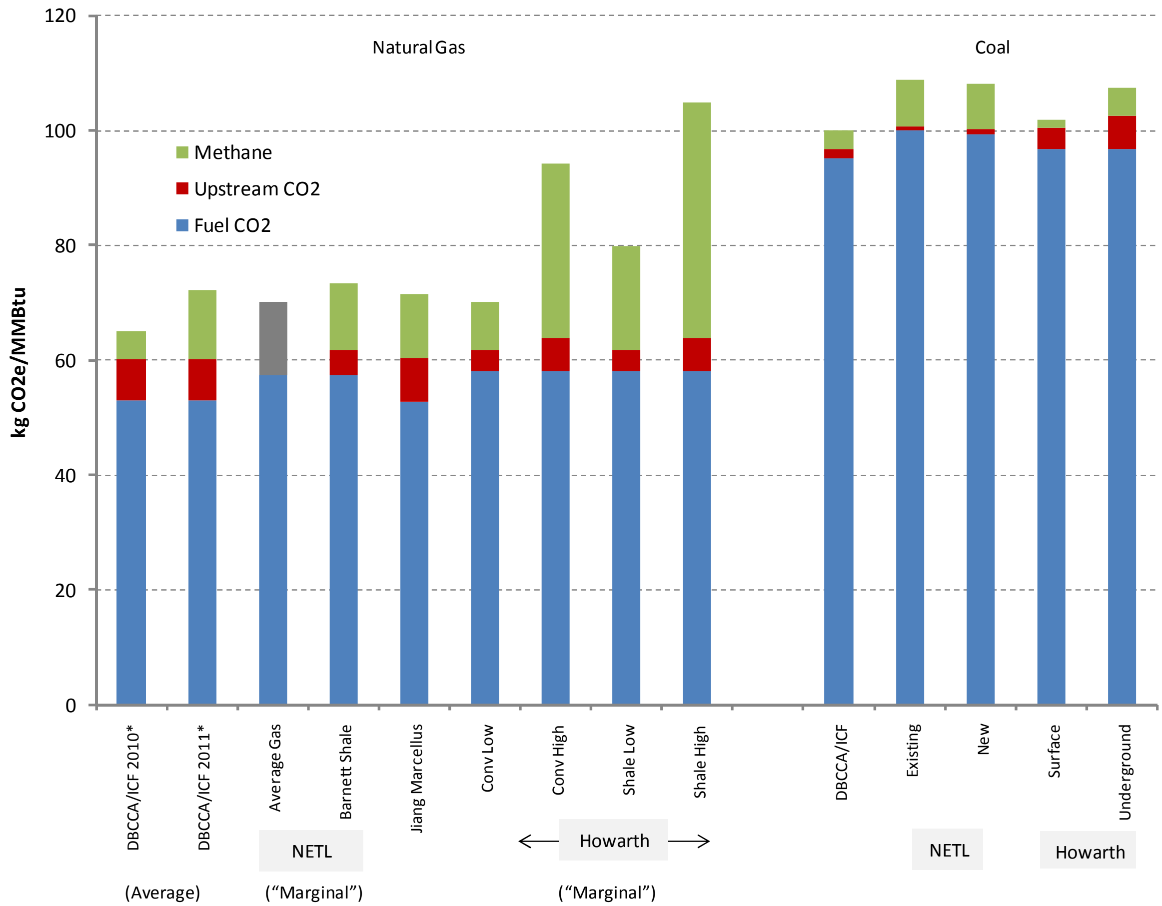
[16] *ORNL, Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, http://cta.ornl.gov/data/index.shtml*

[17] *The results of the top-down life-cycle analysis conducted in the present study are displayed for reference. Bottom-up figures are taken from studies by Skone, et al. 2011 (NETL), Jiang et al. 2011 (Jiang), and Howarth, et al. 2011 (Howarth). All studies are normalized using a 100-year GWP for methane of 25, and given in kg CO_2e per MMBtu of fuel rather than kg CO_2e per MWh of electricity generated. Most studies use MMBtu of fuel produced as their metric; the present study uses MMBtu of fuel consumed, an explanation of which is given on p. 22. .*

Exhibit 2. Comparison of Recent Bottom-Up Life-Cycle Assessments.



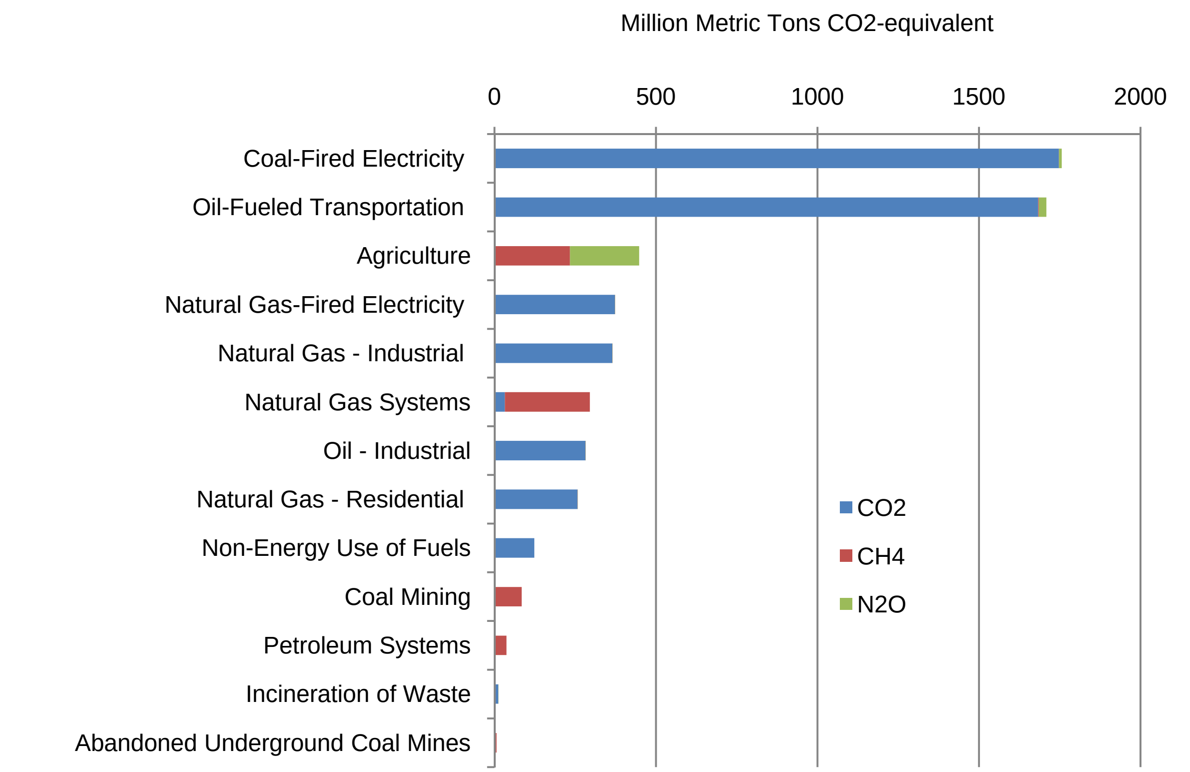
Source: DBCCA Analysis, 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. *2011 EPA methodology compared to 2010.

Many of these studies draw upon data from the U.S. Environmental Protection Agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (hereafter "Inventory" or "Greenhouse Gas Inventory). The Inventory, published annually, is the official U.S. report on GHG emissions to the UN IPCC and the source for much of the analysis of U.S. emissions.[18] The inventory is developed from a variety of public and private data sources on the many different kinds of GHG emission sources in different sectors. It uses a combination of "bottom-up" analysis, utilizing counts and characteristics of individual facilities, and "top-down" analysis, such as national data on fuel combustion from the Energy Information Administration (EIA) to calculate CO_2 emissions from combustion, to build an estimate for total U.S. GHG annual emissions across a range of sectors.

Greenhouse gas emissions from natural gas and coal production, processing, transport, and distribution are estimated in the Inventory's "Natural Gas Systems" and "Coal Mining." In the EPA's 2011 edition of the Inventory, Natural Gas Systems were estimated to be the largest source of non-combustion, energy-related GHG emissions in the U.S., at 296 million metric tons of CO_2 equivalent (MMT CO_2e) in 2009. Coal mining came in third, with an estimated 85 MMT CO_2e of emissions. Fossil fuel combustion accounted for the vast majority of GHG emissions from the U.S. energy sector, with an estimated 1,747.6 MMT CO_2e coming from coal-fired electricity generation alone, while natural gas-fired electricity generation accounted for an additional 373.1 MMT CO_2e (Exhibit 3).[19]

[18] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.
[19] All figures given in CO_2-equivalent here and elsewhere assume a global warming potential of 25 for methane unless otherwise noted. The EPA's Inventory uses a GWP of 21 for reporting purposes, so these numbers were converted to make them consistent with the GWP used for

Exhibit 3. U.S. Greenhouse Gas Emissions by Source Category, 2009.



These are the highest-emitting energy and agriculture sector source categories for 2009. Source: EPA 2011. Data were adjusted to use most recent IPCC GWPs for CH_4 and N_2O (25 and 298, respectively).

We draw two main conclusions from our survey of recent bottom-up life-cycle assessments. First, **the natural gas industry's practices are evolving rapidly, and better data are essential to ensuring that life-cycle greenhouse gas assessments remain up-to-date and reflect current industry behavior**. All of the bottom-up life-cycle assessments we surveyed identified significant uncertainty around certain segments of the natural gas life cycle stemming from data inadequacy. Among the sources of uncertainty identified were: formation-specific production rates, flaring rates during extraction and processing, construction emissions, transport distance, penetration and effectiveness of green completions and workovers, and formation-specific gas compositions.

Second, because shale gas appears to have a GHG footprint some 8 to 11 percent higher than conventional gas on a life-cycle basis per mmBtu based on these bottom up studies that we reviewed, **increased production of shale gas would tend to increase the average life-cycle GHG footprint from U.S. natural gas production if methane emissions from the upstream portion of the natural gas life are unmitigated**. This fact underlines **the importance of implementing the many existing control technologies and practices that can significantly reduce the overall greenhouse gas footprint of the natural gas industry**. Many companies are already reducing vented and flared methane emissions voluntarily through the EPA's voluntary Natural Gas STAR program. For example, the Inventory estimates that the completion emissions of methane from two thirds of shale gas production are already being mitigated through flaring or reduced emission completion.[20] If this is correct, then bottom-up life-cycle GHG estimates that do not account for reduced emissions completions are likely too high.

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the main analysis in this paper. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.

[20] *Ibid.*

Stronger regulations limiting methane and other air pollutant emissions from oil and natural gas operations are also likely to lead to lower overall GHG emissions. Some states already require the adoption of certain methane controls: Wyoming and Colorado, for example, already require “no-flare” or “green” completions and workovers, which are reported to capture 70 to 90 percent of methane vented during completions and workovers following hydraulic fracturing. Because this methane can then be sold, users of green completions have reported payback times of less than one year.[21] Moreover, the EPA released proposed regulations for the gas production sector on July 28, 2011 that are expected to require mitigation of completion emissions from all wells.[22] This regulation is currently in the comment period and is set to be implemented by court order in 1Q12. If these regulations are adopted, there will be little or no difference between the emissions of hydraulically fractured and conventional gas wells.

Top-Down Life-Cycle Analysis of U.S. Natural Gas and Coal: Impact on the Average

The remainder of this paper develops a top-down life-cycle greenhouse gas analysis of natural gas and coal for the purpose of determining the impact of recent EPA revisions to methane emissions estimation methodologies on the current comparison between U.S. natural gas and coal-fired electricity.

Natural Gas

This analysis for natural gas includes each of the industry steps described in Exhibit 1 above. (See Appendix A for a detailed methodology.) The source of information for methane emissions and non-combustion CO_2 is the EPA’s *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* (April 2011 release), which includes updated estimates for methane emissions from natural gas production that are approximately twice the level indicated in the previous 2010 edition.[23] This LCA uses the data from both 2010 and 2011 EPA inventory reports to illustrate the effect that the EPA’s latest increase in estimated methane emissions has on the overall LCA for gas (as discussed below), which we estimate to be about an 11 percent increase in the life-cycle emissions.

The U.S. Energy Information Administration (EIA) is the primary source for the data on natural gas consumption and associated CO_2 emissions in the various segments of the gas industry (fuel for gas compressors and gas processing plants).[24] In addition to the natural gas, petroleum is used for drill rigs, trucks and other mobile equipment, such as pumps for hydraulic fracturing. This analysis uses information from the Economic Census to estimate non-natural gas energy consumption and associated CO_2 emissions in the production sector.[25]

Sources of methane emissions are many and vary widely. Apart from EIA there are very few sources of aggregated data in the public domain. As noted earlier, the EPA recently increased its estimates significantly for several processes in natural gas production, and better data availability on methane leakage and venting will be critical going forward given the rapidly evolving gas production landscape. On this score, disclosures and reporting of upstream emissions have historically been voluntary. And while there is evidence that large volumes of GHGs are being captured by industry, the actual penetration rates of these voluntary programs is unknown[26].

For example, the EPA Natural Gas STAR program, a voluntary methane mitigation program, reports that its members reduced methane emissions from natural gas systems by 904 billion cubic feet between 2003 and 2009—equivalent to 365 $MMTCO_2e$.[27] This program has identified and documented many methane mitigation measures that could be applied more widely across both industries and are included in the EPA’s Inventory of US Greenhouse Gas Emissions

[21] EPA, Natural Gas STAR Program, “Reduced Emissions Completions: Lessons Learned,” available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf, viewed 2 August 2011.
[22] *EPA, “Oil and Natural Gas Air Pollution Standards,” http://epa.gov/airquality/oilandgas/, viewed 18 August 2011.*
[23] *The new EPA data have raised questions on two ends, with some believing the estimates are too high and others believing they are too low. Some comments submitted to the EPA from gas producers about the Draft Inventory question the validity of these revisions, believing them too high. While on the other hand, there are environmental advocacy groups that question whether EPA’s “activity factors” used in its methodology accurately represent the preponderance of shale wells being drilled in the Gulf Coast and North East regions, thereby raising the question of whether the emission factors are indeed high enough.*
[24] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[25] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*
[26] *Reported 2009 Natural Gas STAR voluntary emission reductions were the equivalent of ~$344 million in revenue (assuming $4/mmBtu gas) and the avoidance of 34.8 mn tonnes CO_2e; http://www.epa.gov/gasstar/accomplishments/index.html#content*
[27] *EPA Natural Gas STAR Program Accomplishments, page 2; http://www.epa.gov/gasstar/accomplishments/index.html*

and Sinks report.[28] Additionally, many mitigation activities are not reported to these programs. It is also possible that the EPA is missing or has underestimated some sources of upstream emissions for both natural gas and coal. Nevertheless, we expect that better information will be available in the spring of 2012 when reporting of data on upstream methane emissions through EPA's GHG Reporting Program commences.

In our LCA, the emission factors for the combustion of natural gas, coal and petroleum includes the CO_2 from complete combustion of the fuel plus the small amounts of nitrous oxide (N_2O) and unburned methane that result from the combustion. The emission factors for fuel combustion are taken from subpart C of the EPA Greenhouse Gas Reporting Program.[29] The N_2O and methane emissions from combustion are less than 1% of the CO_2 emissions. The total emission factors for combustion are:

- Natural gas – 53.07 kg CO_2 e/MMBtu
- Diesel fuel – 74.21 kg CO_2 e/MMBtu
- Coal – 95.11 kg CO_2 e/MMBtu

Exhibit 4 summarizes the data on total upstream GHG emissions calculated for the natural gas sector for the year 2008 using the April 2011 EPA inventory for methane adjusted for a methane GWP of 25 and the EIA data on fuel consumption. According to this inventory, U.S. production, processing, and transport of natural gas emitted 387.0 million tons of CO_2 equivalent ($MMTCO_2e$) in 2008.

Exhibit 4. Baseline U.S. Upstream Gas Emission Data for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

In this analysis, we adjust several factors to more accurately and robustly capture the life-cycle emissions associated with the use of natural gas on a national basis.

First, the emissions estimates account for natural gas production in the United States; however, because 13 percent of natural gas consumed in the U.S. was imported in 2008, we increase the production and processing emissions estimates to account for emissions from gas imports. Of that 13 percent in 2008, 11.7 percent was imported by pipeline from North America, mostly from Canada. The analysis assumes that other North American production operations are similar to those in the United States, so the emissions are increased linearly to account for these imports. In addition, 1.3 percent of the gas supply arrived via liquefied natural gas (LNG) imports. The LNG life cycle includes additional emissions associated with liquefaction, transportation, and regasification from source to use. The LNG portion is escalated by 76 percent to account for these emissions, based on a bottom-up LNG LCA prepared by NETL.[30] These are the most significant modifications made in our analysis, increasing the overall LCA for natural gas by 39 $MMTCO_2e$, or about 10 percent, primarily due to the adjustment for pipeline imports.

A second adjustment relates to methane emissions from distribution lines at local gas distribution companies. Since only 52 percent of the gas used for power generation is delivered by local distribution lines, the methane emissions associated with distribution have been discounted by that amount.[31] This reduces the total emissions by 18 $MMtCO_2e$, or 4 percent.

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[28] *EPA,* Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, April 2011, available at http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, p. 152.*
[29] *EPA, Greenhouse Gas Reporting Program, Subpart C, U.S. Environmental Protection Agency, http://www.epa.gov/climatechange/emissions/ghgrulemaking.html*
[30] *Skone, T.J., 2010. Life Cycle Greenhouse Gas Analysis of Power Generation Options, National Energy Technology Laboratory, U.S. Department of Energy*
[31] *EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB*

A final adjustment is for methane emissions from production of associated gas—gas produced from oil wells. We did this in order to accurately adjust the impact of associated gas in our net import correction. Most oil wells produce some natural gas, and some of this gas is collected and becomes part of the gas supply. The EPA inventory of U.S. GHG emissions estimates that methane emissions from petroleum systems are approximately 30 MMTCO_2e per year.[32] Since some domestic natural gas is co-produced with petroleum, these emissions could be considered for inclusion in the LCA of emissions from the natural gas sector.

The associated natural gas produced and the methane emitted during petroleum production, processing, and transport are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. By this assessment it would not be appropriate to count the methane emissions from petroleum production, since they are independent of the production of gas.

On the other hand, associated gas produced from oil wells represents a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the LCA, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production. This calculation is shown in Appendix A and results in an additional 5 MMTCO_2e of emissions being added, or a 1.4 percent increase.

Exhibit 5 shows our adjusted total emissions for 2008, which come to 423.8 MMTCO_2e compared to the 387.0 baseline. The production segment is the largest contributor to GHG emissions from the natural gas supply chain, accounting for 57 percent of total emissions. Of the different gases, methane accounts for 59 percent of total GHG emissions using a GWP of 25.

Exhibit 5. Adjusted Total Upstream GHG Emissions from Natural Gas, 2008 (MMTCO_2e)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

To compare emissions from coal and natural gas on an apples-to-apples basis, the emissions are normalized to the amount of GHG per million Btu (MMBtu) of *natural gas delivered to consumers* using EIA data for gas deliveries[33]. Some LCAs normalize to GHG per unit of natural gas *produced*, which includes associated gas that is reinjected into the producing formation as well as natural gas liquids that are removed during gas processing and gas lost through fugitives and venting, in addition to gas actually delivered to consumers such as power plants. Using delivered rather than produced natural gas results in a slightly higher overall figure for life-cycle emissions but depicts more accurately the energy that is actually available to power plants. The total normalized upstream emissions are 19.2 kg CO_2e/MMBtu of natural gas delivered. (See Exhibit 6.) As discussed earlier, the emissions for combustion of the natural gas at the power plant are 53.1 kg CO_2e/MMBtu, so the total life-cycle GHG emissions at the point of use are 72.3 kg/MMBtu. Of this, the upstream emissions are 30 percent, 60 percent of which are from methane.

[32] *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009, EPA 340-R-11-005, April 2011 page, 27*
[33] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

Exhibit 6. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2011 Methane Emissions Methodolgy (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

Doing the same calculation with the lower methane emissions estimated in the prior year's EPA inventory yields a value of 12.0 kg CO_2e/MMBtu for the upstream emissions. (See Exhibit 7) Including the end-use gas consumption, total life-cycle emissions are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit 7. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2010 Methane Emissions Methodology (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Finally, Exhibit 8 applies the most recent EPA data to calculate the life-cycle emissions for 2009 using the 2011 methane emissions methodology. This is the most recent year for which data are available. The 2009 emissions are quite similar to the emissions calculated for 2008 using the same methodology (73.1 vs 72.1 expressed as kg CO2e/MMBtu).

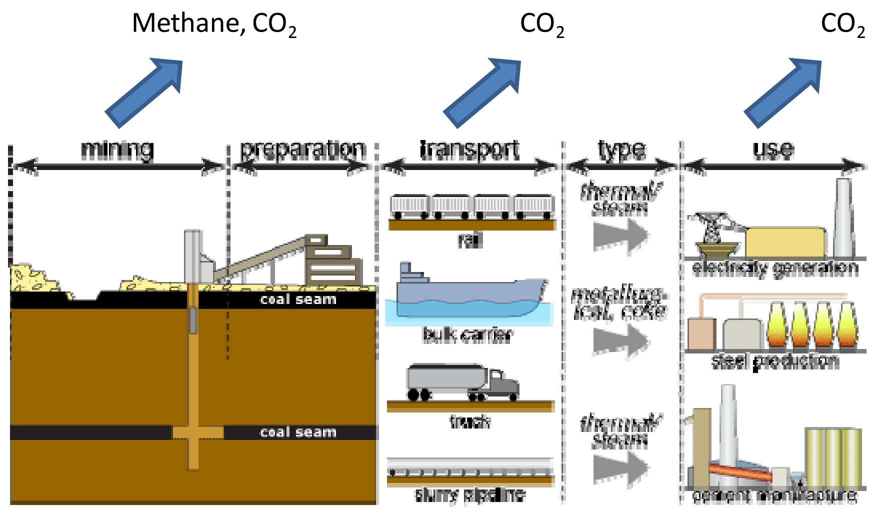
Exhibit 8. Normalized Life-Cycle GHG Emissions for Natural Gas for 2009, using EPA 2011 Methane Emissions Methodology (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	8.4	0.6	3.0	12.0
Processing	1.1	1.1	1.0	3.2
Transmission	2.4	0.0	1.6	4.0
Distribution	0.8	0.0	0.0	0.8
Upstream Total	12.8	1.7	5.6	20.1
Fuel Combustion	0.0	0.0	53.1	53.1
Total	12.8	1.7	58.7	73.1

Coal

The production and distribution of coal is simpler to analyze than that of natural gas because there are fewer steps in production and processing (Exhibit 9). Coal is produced in the U.S. from underground mines (40 percent) and surface mines (60 percent). In underground mines, most of the mining equipment is driven by electricity. In surface mines, the equipment runs on diesel fuel or electricity. This analysis estimates the direct and indirect emissions of the mining processes from Economic Census data[34]. (For detailed calculations of the coal LCA, see Appendix A.)

Exhibit 9. Coal Industry Segments and Emission Sources



Source: University of Wyoming

Coal formations contain methane, which is released when the coal is mined. The methane content varies among different coal formations but is generally higher for underground mines than for surface mines. Underground mines use ventilation to remove the methane, which is a safety hazard, and in some cases the methane can be recovered for use or flared to reduce GHG emissions. The U.S. GHG Inventory estimates the methane emissions from coal mining. Coal mines that are no longer active (i.e., are "abandoned") release methane as well: 7.0 MMTCO$_2$e in 2008 (at 25 GWP). This would add an additional 0.4 kg CO$_2$e/MMBtu to the coal LCA but is not included here since we do not have similar data on methane emissions from abandoned gas wells.

Data on coal transportation by mode are available from the Economic Census[35]. More than 90 percent of coal is transported by train, with the remainder transported by barge, truck, or various combinations of these modes. This analysis derives the energy consumption per ton-mile from several sources to calculate CO_2 emissions. (See Appendix A.)

The United States is a net exporter of coal by 4 percent, so the production data are adjusted downward by that amount. Table 6 shows the adjusted upstream GHG emissions for coal, totaling 117.8 MMTCO$_2$e.

[34] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*
[35] *Ibid.*

Exhibit 10. Adjusted Total Upstream GHG Emissions from Coal for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

As with the natural gas LCA, this analysis "normalizes" total emissions by the energy delivered to coal consumers (more than 90% power of whom are power generators), or 1,147 million short tons of coal in 2008. This yields a normalized upstream emission factor of 4.8 kg CO_2e/MMBtu consumed. (See Exhibit 11.) This value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg/MMBtu, bringing the total end-use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane comprises 63 percent of the upstream emissions, the upstream component is only 5 percent of the total, with CO_2 emissions from the combustion of the coal itself being the dominant factor in the total life-cycle emissions.

Exhibit 11. Normalized Life-Cycle GHG Emissions from Coal for 2008 (kg CO_2e/MMBtu)

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

Finally, life-cycle GHG emissions per MMBtu of fuel delivered to power plants are normalized to GHG emissions per MWh of electricity generated to account for the difference in coal and natural gas power plant efficiencies. In 2008, essentially all coal-fired electricity in the United States was generated by steam-turbine power plants, which combust fuel to boil water and use the resulting steam to drive a turbine.[36] Many coal plants are run almost all the time at full capacity to provide baseload power. Technology has improved over the past several decades and new plants have improved combustion efficiencies, but many active plants in the U.S. fleet were built before 1970 and are less efficient.

By contrast, natural gas is used in a range of power plant technologies, each of which fills a different role in the electricity dispatch. In 2008, only 12 percent of natural gas-fired electricity was generated by steam-turbine plants, most of which were built before 1980 and are relatively inefficient. An additional 9 percent was generated by simple-cycle gas turbines, relatively inefficient plants that are used to provide peaking power during limited periods. Since 2000, a large portion of new natural gas capacity additions have been combined-cycle units, which use waste heat from gas turbines to run steam turbines.

Combined-cycle plants have superior heat rates and may be used to provide baseload or intermediate power, depending on the particular grid and the price of gas. In 2008, 79 percent of gas-fired electricity was generated by combined-cycle plants. Two coal plants in the U.S. currently gasify coal to generate electricity in a combined-cycle configuration, but such plants, called Integrated Gasification Combined Cycle (IGCC) plants, have very low market penetration today.

[36] *All 2008 generation data from Energy Information Administration (EIA), Form EIA-923, 2008.*

The heat rate (the amount of fuel in Btus needed to generate a kilowatt-hour of electricity) of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity.[37] Unless otherwise specified, this analysis uses heat rates representing the average efficiency of existing power plants in the U.S. fleet:

- **Average efficiency of existing capital stock:** National average values are based on EIA data for total gas or coal consumption for generation and total generation by each fuel. The heat rates are 8,044 Btu/kWh (41 percent efficiency) for gas generation and 11,044Btu/kWh (31 percent efficiency) for coal generation.

A sensitivity analysis comparing life-cycle emissions results using average heat rates and heat rates representative of new natural gas and coal plants is shown in Appendix A (Exhibit A-12).

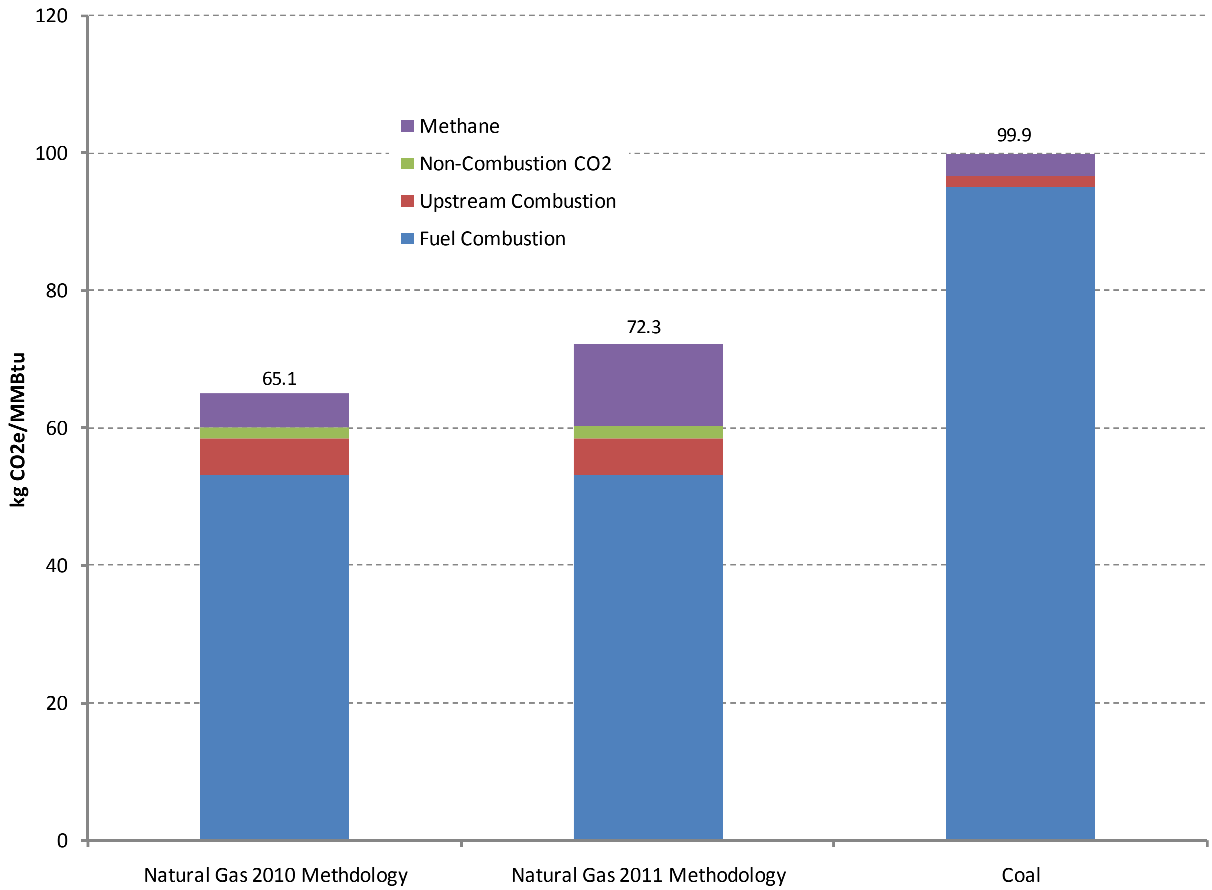
- **Efficiency of new plants:** In its *Annual Energy Outlook 2010*[38], EIA provides a value for a new plant in 2009, and for future plants that accounts for future cost reductions from learning and production efficiencies ("nth" plant). The values used here are the average of the two values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency).

Summary of Results and Sensitivity Analysis for Top=Down Analysis

Exhibit 12 compares the calculated LCA emissions (by GHG) for gas delivered to power plants for (a) natural gas using the EPA 2010 methodology, (b) natural gas using the EPA 2011 methodology, and (c) coal. In all cases, the emissions are dominated by CO_2 from final combustion of the fuel at the power plant. The upstream emissions are larger for gas, and the power plant combustion emissions are higher for coal. The LCA for coal is dominated by the CO_2 from the coal combustion itself. The upstream component is larger for natural gas, and methane is a larger component of the emissions. Using the increased methane emission estimate for gas from the 2011 methodology results in the LCA for natural gas being 11 percent higher than with the 2010 estimate. The gas life-cycle value using the 2011 methodology is 28 percent lower than the coal value.

[37] The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate in Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.
[38] *EIA, Assumptions to the Annual Energy Outlook 2010 – Table 8-2,* DOE/EIA-0554(2010), *Energy Information Administration, U.S. Department of Energy.* http://www.eia.gov/oiaf/aeo/assumption/pdf/electricity_tbls.pdf

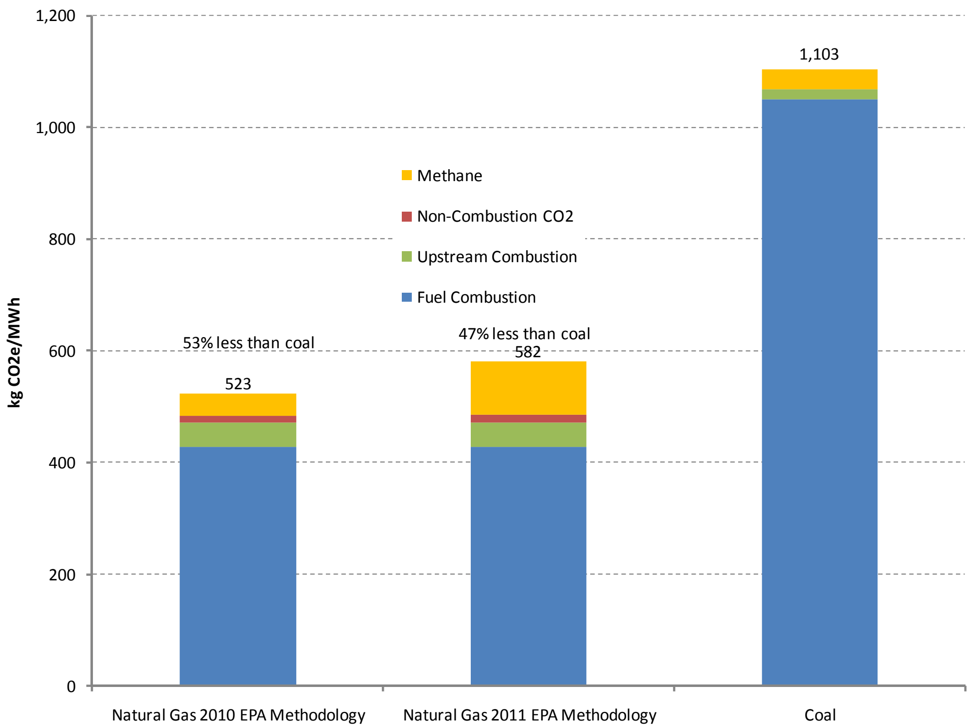
Exhibit 12: Life-Cycle Emissions as Delivered to Power Plants, 2008 (kg CO_2e/MMBtu)



Source: DBCCA Analysis 2011

Exhibit 13 shows the LCA in terms of GHG emissions per megawatt-hour of electricity generated from gas and coal, using the national average power plant efficiencies. The gas value using the 2011 EPA methane emissions estimates is 582 kg CO_2e/MWh—or 11 percent higher than the 523 kg CO_2e/MWh calculated using data for 2010 methodology. The value for coal is 1,103 kg CO_2e/MWh. Because coal plants are on average less efficient than gas plants, the difference between gas and coal is greater than the fuel-only comparison at the burner tip prior to combustion and conversion to electricity. **Natural gas-fired electricity, using the 2011 methodology, has 47 percent lower life-cycle GHG emissions per unit of electricity than coal-fired electricity.**

Exhibit 13: Electric Generating LCA, by Greenhouse Gas, 2008 (kg CO_2e/MWh)



Source: DBCCA Analysis 2011

Conclusions

Our top-down LCA of natural gas and coal-based generation using publicly available data shows that the EPA's recent revision of methane emissions increases the life-cycle GHG emissions for natural gas-fired electricity by about 11 percent from estimates based on the earlier values. Our conclusion is that, on average, natural gas-fired power generation emits significantly fewer GHGs compared to coal-fired power generation. Life-cycle emissions for natural gas generation using new EPA estimates are 47 lower than for coal-based generation when using a GWP of 25. The impact of different GWPs to our LCA can be found in Appendix B.

Nevertheless, methane, despite its shorter lifetime than carbon dioxide, is of concern as a GHG. Compared to coal-fired generation, methane emissions, including a large venting component, comprise a much larger share of natural-gas generation's GHGs. And while measurement of upstream emissions and public disclosure of those emissions still has room for improvement, methane emissions during the production, processing, transport, storage, and distribution of natural gas can be mitigated now at moderately low cost using existing technologies and best practices. Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas.

Appendix A
Detailed Methodology and Calculations

Natural Gas

The natural gas LCA addresses emissions from extraction through electricity generation for 2008. The primary data sources are the EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* and EIA data on natural gas consumption[39]. Exhibit A-1 shows the basic information on total emissions by industry segment for 2008. The methane emissions are from the EPA Inventory and adjusted from a GWP of 21 to a GWP of 25. The non-combustion CO_2 emissions are from the same source and include CO_2 from combustion of flared gas and the formation CO_2 vented from gas processing plants. The CO_2 from combustion is primarily from the EIA data on gas consumption in the gas industry. The gas consumed in the production segment is the "lease gas" reported by EIA, which is gas consumed in the producing areas. EIA also reports "vented and flared gas," which is assumed here to be all flared but is already included in the EPA category of non-combustion emissions. The "processing" category includes the "plant gas" reported by EIA, and "transmission" includes the pipeline and distribution fuel reported by EIA. The total upstream emissions from these sources are 387.0 $MMTCO_2e$ based on a 100 year GWP of 25.

Detailed data collection and verification, as well as LCA harmonization to common metrics and system boundaries are critical for improving the rigor of LCA analysis. The National Renewable Energy Laboratory's Joint Institute for Strategic Energy Analysis, www.jisea.org, will be conducting such an evaluation in the coming months, which may improve upon the historical data sets used by EPA.

Exhibit A-1: Basic U.S. Upstream Gas Emission Data for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

There are several additions to this basic information. First, there are some electric driven compressors on the pipeline network. This electricity consumption of 2,936.6 million kWh is from the ORNL *Transportation Data Book*[40]. (That estimate is based on a fixed share of 1.5 percent of the natural gas consumption.) The emission factor for electricity throughout the analysis is 603 kg CO_2/MWh, calculated from EIA data on total generation and CO_2 emissions. This electricity consumption adds 1.8 $MMTCO_2e$ to the pipeline emissions. There is also diesel fuel, gasoline and other petroleum fuel used in gas drilling and production that is not separately reported by EIA. This information is collected by the Economic Census[41]**Error! Bookmark not defined.** but only by NAICS code and only every 10 years (the latest reporting year is 2007). The four relevant NAICS codes are: 211111 (crude petroleum and natural gas extraction); 211112 (natural gas liquid extraction); 213111 (drilling oil and gas wells); and 213112 (support activities for oil and gas operations).

Three of these codes (excepting NGL extraction) combine data for oil and gas operation. The gas portion is calculated based on the gas share of U.S. producing oil and gas wells (55.4 percent) or active drilling rigs (83.2 percent). Also, the Census lists expenditures only by fuel type. The actual consumption is estimated from the expenditures based on average price for each fuel. The consumption is then converted to CO_2 emissions using the emission factors from the EPA GHG Reporting Program. These emissions are then escalated from 2007 to 2008 based on EIA data for production (3.9 percent increase). The calculations are summarized in Exhibit A-2. Total emissions for this segment are 7.2 $MMTCO_2e$.

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[39] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[40] *ORNL, Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, http://cta.ornl.gov/data/index.shtml*
[41] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

Exhibit A-2: Gas Industry Upstream Non-Gas Emissions

Energy Consumption (MMBtu)						
NAICS		Distillate	Gasoline	Other	Residual Oil	Undistributed
211111	Extraction	29,055,998	10,031,608	--	6,539,144	8,502,932
211112	NGL Extraction	288,585	352,861	66,627	--	168,613
213111	Drilling	10,014,334	3,808,638	551,713	3,967,479	5,446,747
213112	Support	20,671,552	13,157,404	893,604	7,166,105	4,389,137

CO_2 Emission Factors		Distillate	Gasoline	Other	Residual Oil	Other
		73.96	70.22	62.98	75.1	62.98

CO_2 Emissions ($MMTCO_2e$)						
211111	Extraction	2.1	0.7	0	0.5	0.5
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.7	0.3	0	0.3	0.3
213112	Support	1.5	0.9	0.1	0.5	0.3

Gas Share of Emissions ($MMTCO_2e$)						
21111	Extraction	1.8	0.6	0	0.4	0.4
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.4	0.1	0	0.2	0.2
213112	Support	1.3	0.8	0	0.4	0.2

Source: EPA, ORNL, Census Bureau, DBCCA Analysis 2011

Another adjustment is for methane emissions from “associated” gas produced from oil wells. Most oil wells produce gas, much of which is captured and delivered to consumers. The EPA *Inventory of U.S. GHG Emissions* estimates methane emissions from petroleum systems to be approximately 30 $MMTCO_2e$ per year.

Since some domestic natural gas is co-produced with petroleum, one could consider all of these emissions be included in the life-cycle analysis of emissions from the natural gas sector. However, the natural gas produced and the methane emissions are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. One could also therefore maintain that it is not appropriate to count the methane emissions from petroleum production toward gas use, since they are independent of the production of gas and are related to petroleum consumption.

On the other hand, associated gas produced from oil wells is a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the life-cycle analysis, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production.

The EPA inventory separates the methane emissions from petroleum systems at the wellhead oil separator. Methane emitted on the oil side downstream from the separator is allocated to the petroleum side, and methane emitted on the natural gas side is allocated to the natural gas side. The part that must be allocated here is the upstream production emissions, of which the largest components are miscellaneous venting and fugitives and venting from gas-powered pneumatic devices. The approach in this analysis is to simply allocate these emissions based on the energy value of oil versus gas produced from these wells.

According to the EIA, the gross production of natural gas from petroleum wells in 2008 was 5.7 trillion cubic feet (Tcf)[42]. However, much of this gas (3.3 Tcf) was not gathered for sale but was reinjected into the producing formation. Some of the gas is reinjected to push more oil out of the formation. Most of the reinjection (3.0 Tcf) is from Alaska production where there is no pipeline to bring the gas to market. It is reinjected as a means of storage until the time when a pipeline may be built to the lower 48 states. In any case, the associated gas actually produced for potential sale is 2.5 Tcf. On an energy basis, this is 20 percent energy value of the net associated gas plus the 1.8 billion barrels of U.S. oil production in 2008.

Of the methane emission sources in petroleum production, we include pneumatic device venting, combustion and process upsets, miscellaneous venting and fugitives, and wellhead fugitives. Tank venting is not included because it is purely related to oil production. Total methane emissions for these sources in 2008 were 25.6 $MMTCO_2e$, according to the EPA inventory. Taking 20 percent of this total gives 5.0 $MMTCO_2e$ of additional methane emissions to allocate to the natural gas LCA, increasing the unadjusted emission baseline by 1.4 percent.

With these additions (electricity, non-gas fuel, and methane from petroleum systems), total upstream gas production emissions are 402.0 $MMTCO_2e$.

The total emissions are then adjusted for imports. The calculations above include emissions for U.S. production, but a net 13 percent of natural gas was imported in 2008. Of this, 11.7 percent was imported by pipeline from Mexico and Canada (mostly the latter). This analysis assumes that production processes are similar throughout North America, so the production emissions are escalated by 11.7 percent to account for the pipeline imports. The remaining 1.3 percent of imports were LNG imports. LNG has a higher LCA than conventional gas due to gasification, liquefaction, and transportation processes. The LCA for LNG is estimated at 176 percent of conventional gas based on the LCA performed by NETL[30] The production emissions for the LNG component are increased by this amount. The adjustment for imports is the largest adjustment, increasing the emissions by about 39 $MMTCO_2e$, or 10 percent.

The other adjustment in this analysis is related to fugitive methane emissions from gas distribution lines at local gas distribution companies (LDCs). Methane emissions from local distribution lines are 35.6 $MMTCO_2e$ (at 25 GWP), but many power plants receive gas deliveries directly from interstate pipelines rather than via local distribution lines. Relatively few power plants actually purchase gas from LDCs, but some receive gas deliveries from the LDCs. The EIA-176 survey[43] provides data on deliveries by LDCs to electric generators; however, these reported deliveries total 6.5 Tcf, which is almost equal to total gas consumption for electricity generation. This is because intrastate pipeline deliveries in California, Texas, and Florida are included in the EIA-176 survey. Excluding these three states, 59 percent of gas to electric generators is delivered by LDCs. Based on this, only 59 percent of the distribution company methane emissions are included in the adjusted values. This adjustment decreases the emissions by about 17 $MMTCO_2e$, or 4 percent. Exhibit A-3 shows the adjusted final upstream GHG emissions for natural gas: 423.8 $MMTCO_2e$. Methane emissions account for more than half of the total.

Exhibit A-3: Adjusted Total Upstream GHG Emissions from Natural Gas for 2008, using EPA 2011 Methodology for Methane ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

These total emissions are then normalized to kg CO_2e/MMBtu of delivered natural gas based on the EIA data on natural gas delivered to consumers: 21.4 trillion cubic feet (Tcf). The total normalized upstream emissions are 19.2 kg CO_2e/MMBtu. (See Exhibit A-4.) The emissions for combustion of the gas at the point of use are 53.07 kg

[42] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[43] *EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB*

CO_2e/MMBtu (including N_2O and unburned methane), so the total life-cycle GHG emissions at the point of use are 70.4 kg CO_2e/MMBtu. Of this, the upstream emissions are 24 percent and methane is slightly over half of the upstream component.

Exhibit A-4: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2011 EPA Methodology for Methane (kg CO_2/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

The same methodology is applied using EPA's 2010 estimate of methane emissions, to show the effect of the updated, increased 2011 methane emission estimate. Exhibits A-5 and A-6 show the total and normalized emissions for this case. The normalized upstream emissions with the old data are 12.0 kg CO_2e/MMBtu. Including the end-use gas combustion; total life-cycle emissions including end-use combustion are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit A-5: Adjusted Total Upstream GHG Emissions from Natural Gas, 2008, using 2010 EPA Methodology for Methane (MMTCO_2e)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	25.9	9.7	62.2	97.8
Processing	17.7	24.4	22.2	64.2
Transmission	46.9	0.1	37.2	84.2
Distribution	18.3	0.0	0.0	18.3
Total	108.8	34.2	121.5	264.6

Exhibit A-6: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2010 EPA Methodology for Methane (kg CO_2/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Coal LCA

The upstream energy consumption for coal production is calculated using the 2007 Economic Census[44] data on fuel and electricity consumption in the same way as the non-gas fuel for gas production. In this case, there is a separate NAICS code for coal production, so no adjustments are necessary. The same CO_2 emission factors and the emission factor for electricity use are used as for the data on gas production. (See Exhibit A-7.) The values are adjusted from 2007 to 2008 based on the production in each year—a 2.2 percent increase. The total CO_2 emissions from energy consumption for coal production are 14.0 $MMTCO_2e$. Methane emissions from coal mines of 67.1 $MMTCO_2e$ (79.9 at 25 GWP) are taken from the EPA GHG inventory. Methane from abandoned coal mines is not included.

Exhibit A-7: Upstream GHG Calculation for Coal

	Coal	Distillate	Natural Gas	Gasoline	Residual Oil	Other	Electricity (MWh)
MMBtu	3,607,020	52,597,178	2,487,920	4,846,529	25,739,212	2,039,820	11,444,477
kg CO2/MMBtu	94.38	73.96	53.02	70.22	75.10	62.98	603.01
MMTCO2e	0.34	3.89	0.13	0.34	1.93	0.13	6.90

The estimate of transportation emissions is based on the Commodity Flow Summary[45] developed by the U.S. Department of Transportation and Census Bureau, which provides information on ton-miles of coal transported by different modes. Rail is the primary mode of transportation, with rail-only accounting for 91 percent of the ton-miles and rail and other modes (truck and barge) accounting for the remainder. This analysis applies a ton-mile fuel consumption factor[46, 47, 48] to calculate fuel consumption and converts the fuel consumption to CO_2 using the same EPA emission factors used for other sectors. (See Exhibit A-8.) For mixed mode, rail or barge are assumed to account for 75 percent of the ton-miles and truck for 50 percent. Most coal is delivered via dedicated equipment—e.g., a coal unit train travels only to and from the mine to the power plant. Thus, the fuel consumed in returning empty to the mine must be included. This analysis assumes 100-percent empty return as part of the energy consumption, with the empty fuel consumption being one-third of the loaded consumption based on the weight of the empty vehicle. The total consumption calculated is 23.9 $MMTCO_2$.

Exhibit A-8: GHG Calculation for Coal Transportation

Mode	Ton-Miles (million)	Fuel Consumption (ton-mi/gal)	GHG Emissions (MMTCO2)	Round-Trip Emissions (MMTCO2)
Truck	14,002	110.00	1.28	1.67
Rail	773,290	480.00	16.26	21.13
Water	6,548	730.00	0.09	0.12
Truck and rail	785	388.00	0.02	0.03
Truck and water	7,257	575.00	0.13	0.17
Rail and water	26,994	605.00	0.45	0.59
Other multiple modes	4,353	480.00	0.09	0.12
Other and unknown modes	2,567	480.00	0.05	0.07
Total	835,796	-	18.38	23.89

In the case of coal, the U.S. is a net exporter of about 4 percent of its production, so the total production emissions are adjusted downward by this amount to calculate the emissions attributable to coal consumed in the U.S. Exhibit A-9 shows the final adjusted upstream emissions: 117.8 $MMTCO_2e$.

[44] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*
[45] *U.S. Department of Transportation, Research and Innovative Technology Administration, Bureau of Transportation Statistics and U.S. Census Bureau, 2007 Commodity Flow Survey.*
[46] *Federal Railroad Administration, "Comparative Evaluation of Rail and Truck Fuel Efficiency on Competitive Corridors", November 19, 2009.*
[47] *Army Corps of Engineers, "Waterborne Commerce Statistics Center", http://www.ndc.iwr.usace.army.mil//data/data1.htm*
[48] *American Railroad Association*

Exhibit A-9: Adjusted Total Upstream GHG Emissions from Coal, 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

These values are then normalized by the total 2008 consumption of coal in the U.S. of 1,147 million tons of coal, assuming an average heating value of 10,250 Btu/lb.[49] This yields a normalized upstream emission factor of 4.3 kg CO_2/MMBtu consumed. (See Exhibit A-10.) The value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg CO_2e/MMBtu, bringing the total end use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane is still 63 percent of the upstream emissions, the upstream component is only 4 percent of the total, with the CO_2 emissions from the coal itself being the dominant factor.

Exhibit A-10: Normalized Upstream GHG Emissions for Coal for 2008 (kg CO_2/MMBtu)

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

The efficiency[50] of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity. This analysis looks at two values:

- **National average efficiency values** based on EIA data[51, 52, 53, 54] for total gas or coal consumption for generation and total generation by each fuel. (See Exhibit A-11.)

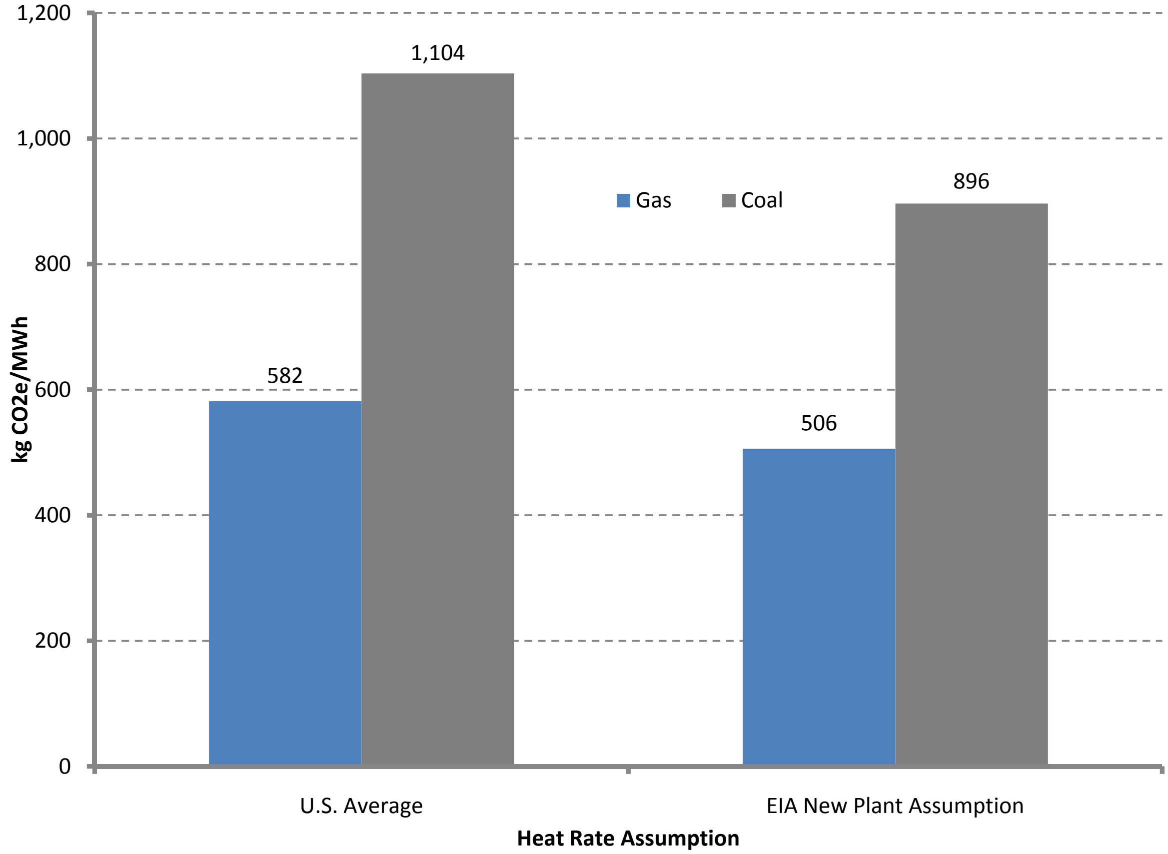
- **Efficiency[55] for new power plants** assumed by the EIA in its *Annual Energy Outlook 2010*[38]. EIA provides a value for a new plant in 2009 and for subsequent plants ("nth plant") of each type for which the cost may be lower due to learning and production improvement. The values used here are the average of the values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency). (See Exhibit A-12.)

Exhibit A-11: Calculation of Average Power Plant Efficiencies

	Energy Consumption (Quads)	Generation (Billion kWh)	Heat Rate (Btu / kWh)	Efficiency
Gas	7	883.00	8,044.00	0.42
Coal	22	1,986.00	11,044.00	0.31

[49] *EIA, Annual Coal Data, Energy Information Administration, U.S. Department of Energy, http://www.eia.gov/totalenergy/data/annual/pdf/sec7_5.pdf*
[50] *The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate is Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.*
[51] *EIA, Electric Power Monthly, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_4_a.html*
[52] *EIA, Electric Power Monthly, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/aer/txt/ptb0802a.html*
[53] *EIA, Annual Energy Review, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_1_a.html*
[54] *EIA, Quarterly Coal Report, U.S. Department of Energy, http://www.eia.gov/cneaf/coal/quarterly/html/t32p01p1.pdf*

Exhibit A-12: Effect of Power Plant Heat Rate on Life-Cycle Emissions



Source: DBCCA analysis, 2011.

Appendix B
Effect of Global Warming Potential (GWP)

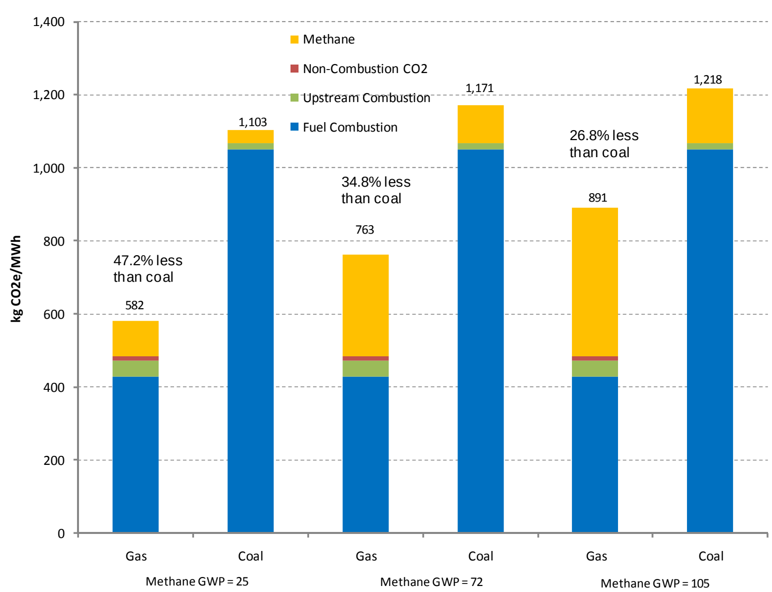
Methane is a potent GHG and its effect varies depending on the lifetime over which it is evaluated. The IPCC uses a 100 year lifetime for its analysis and a 100 year GWP of 25 for methane. Others believe that short-lived GHGs should be evaluated on a 20 year lifetime.

In its recently completed study on natural gas, MIT explains the reasons that a 100 GWP is commonly used:

> *"Because the various GHGs have different lives in the atmosphere (e.g., on the scale of a decade for methane, but centuries for CO_2), the calculation of GWPs depends on the integration period. Early studies calculated this index for 20-, 100- and 500-year integration periods. The IPCC decided to use the 100-year measure, and it is a procedure followed by the U.S. and other countries over several decades. An outlier in this domain is the Cornell study which recommends the application of the 20-year value in inter-fuel comparison. A 20-year GWP would emphasize the near-term impact of methane but ignore serious longer-term risks of climate change from GHGs that will remain in the atmosphere for hundreds to thousands of years, and the 500-year value would miss important effects over the current century. Methane is a more powerful GHG than CO_2, and its combination of potency and short life yields the 100-year GWP used in this study."*[56]

In addition, scientific work continues on the appropriate GWPs for different GHGs. Although the IPCC 20-year GWP for methane is 72, new work by Shindell et al[57] proposes a 20-year GWP of 105 for methane. Exhibit B-1 above shows the effect of different methane GWPs on the LCA using the EPA 2011 methodology. Since methane is a much larger component of the LCA for natural gas, the GWP has a much larger effect on gas than coal. Going from the 100 year GWP to the 20-year GWP of 72 increases life-cycle emissions for natural gas by 31 percent and for coal by only 6 percent. At the GWP of 72, the power plant emissions for natural gas are 35 percent lower than those for coal. At the 105 GWP, the emissions for the gas-fired plant are 27 percent lower than those for coal.

Exhibit B-1: Effect of Methane GWP on Life-Cycle Emissions



Source: DBCCA Analysis 2011

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[56] *The Future of Natural Gas, Moniz, Ernest J.; Jacoby, Henry D.; Meggs, Anthony J.M. (Study co-chairs), MIT Energy Initiative, 2011.*
[57] *Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718*

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LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

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Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of “unconventional” gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a]Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b]Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c]Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d]Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e]Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

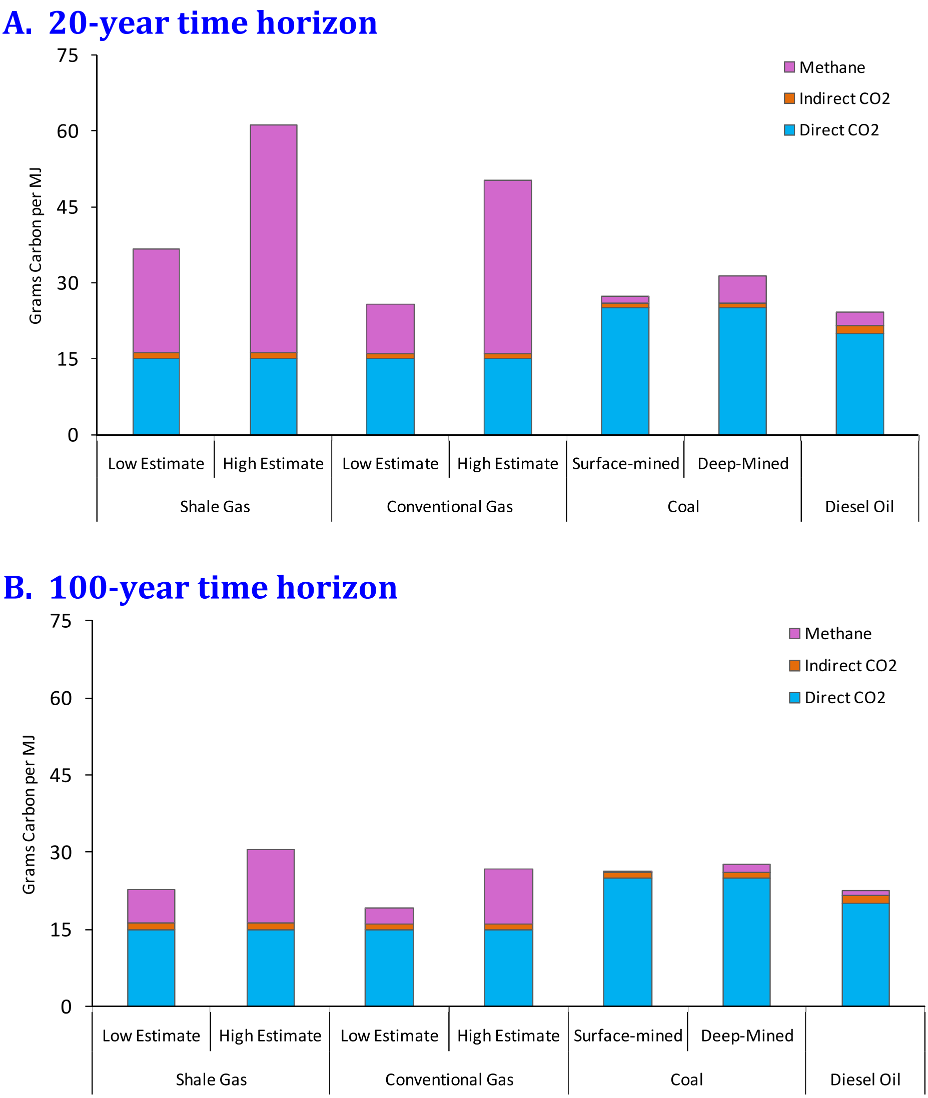

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

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Life cycle greenhouse gas emissions of Marcellus shale gas

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Abstract

This study estimates the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average US natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. We estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide equivalent emissions or about 1.8 g CO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63–75 g CO_2e/MJ of gas produced with an average of 68 g CO_2e/MJ of gas produced. Marcellus shale natural gas GHG emissions are comparable to those of imported liquefied natural gas. Natural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability. There is significant uncertainty in our Marcellus shale GHG emission estimates due to eventual production volumes and variability in flaring, construction and transportation.

Keywords: life cycle assessment, greenhouse gases, Marcellus shale, natural gas

S Online supplementary data available from stacks.iop.org/ERL/6/034014/mmedia

1. Introduction

Marcellus shale is a rapidly developing new source of US domestic natural gas. The Appalachian Basin Marcellus shale extends from southern New York through the western portion of Pennsylvania and into the eastern half of Ohio and northern West Virginia (Kargbo *et al* 2010). The estimated basin area is between 140 000 and 250 000 km^2 (Kargbo *et al* 2010), and has a depth ranging from 1200 to 2600 m (US DOE 2009). The shale seam's net thickness ranges from 15 to 60 m (US DOE 2009) and is generally thicker from west to east (Hill *et al* 2004). Figure 1 shows the location of the Marcellus and other shale gas formations in the continental United States.

Shale gas has become an important component of the current US natural gas production mix. In 2009, shale gas was 16% of the 21 trillion cubic feet (Tcf) or 600 million cubic meters (Mm^3) total dry gas produced (US EIA 2011a, 2011b). In 2035, the EIA expects the share to increase to 47% (12 Tcf or 340 Mm^3) of total gas production. The prospect of rapid shale gas development has resulted in interest in expanding

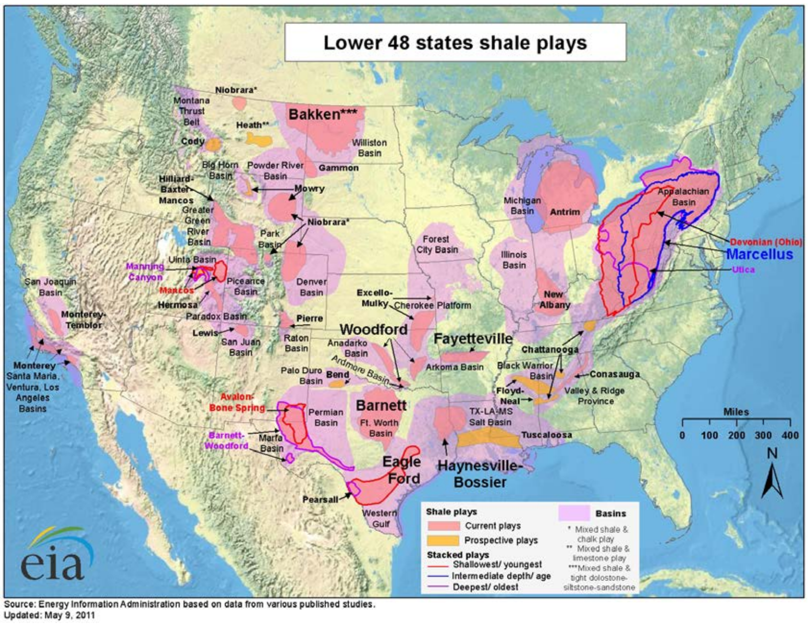

Figure 1. Shale gas plays and basins in the 48 states (source: US Energy Information Administration 2011a, available at http://www.eia.gov/oil_gas/rpd/shale_gas.jpg).

natural gas use including increased natural gas fired electricity generation, use as an alternative transportation fuel, and even exporting as liquefied natural gas. To date most shale gas activity has been in the Barnett shale in Texas. However, the immense potential of the Marcellus shale has stimulated increased attention. The shale play has an estimated gas-in-place of 1500 Tcf or 42 000 Mm^3, of which 262–500 Tcf or 7400–14 000 Mm^3 are thought to be recoverable (Hill *et al* 2004, US DOE 2009).

Advancements in horizontal drilling and hydraulic fracturing, demonstrated successfully in the Barnett shale and first applied in the Marcellus shale in 2004, have enabled the recovery of economical levels of Marcellus shale gas. After vertical drilling reaches the depth of the shale, the shale formation is penetrated horizontally with lateral lengths extending thousands of feet to ensure maximum contact with the gas-bearing seam. Hydraulic fracturing is then used to increase permeability that in turn increases the gas flow.

In this study, life cycle greenhouse gas (GHG) emissions associated with the Marcellus shale gas production are estimated. The difference between GHG emissions of natural gas production from unconventional Marcellus gas wells and average domestic wells is considered to help determine the environmental impacts of the development of shale gas resources. The results of this analysis are compared with life cycle GHG emissions of average domestic natural gas pre-Marcellus and imported liquefied natural gas. In addition domestic coal and Marcellus shale for electricity generation are compared. Other environmental issues may also be of concern in the Marcellus shale development, including disruption of natural habitats, the use of water and creation of wastewater as well as the impacts of truck transport in rural areas. However these environmental issues are outside the scope of our analysis and are not addressed in this paper.

In estimating GHG emissions, we include GHG emissions of carbon dioxide, methane and nitrous oxide. We converted the GHG emissions to carbon dioxide equivalents according to the global warming potential (GWP) factors reported by IPCC. We use the 100-year GWP factor, in which methane has a global warming potential (GWP) 25 times higher than carbon dioxide (IPCC 2007).

2. Marcellus shale gas analysis boundaries and functional unit

The boundary of our analysis and the major process steps included in our estimates are shown in figure 2. Final life cycle emission estimates are reported in grams of carbon dioxide equivalent emissions per megajoule of natural gas ($g\ CO_2e/MJ$) produced. Each of the individual processes in the natural gas life cycle has an associated upstream supply chain and is included in this study to provide a full assessment of GHG emissions associated with Marcellus shale gas. The sources of GHG emissions considered in the LCA include: emissions from the production and transportation of material involved in the well development activities (such as trucking water); emissions from fuel consumption for powering the drilling and fracturing equipment; methane leaks and fuel combustion emissions associated with gas production, processing, transmission, distribution, and natural gas combustion.

The life cycle of Marcellus shale natural gas begins with a 'preproduction phase' that includes the well site investigation, preparation of the well pad including grading and construction of the well pad and access roads, drilling, hydraulic fracturing, and well completion (Soeder and Kappel 2009). After this preproduction phase is completed, the well becomes operational and starts producing natural gas. This natural gas can require additional processing to remove water, CO_2 and/or

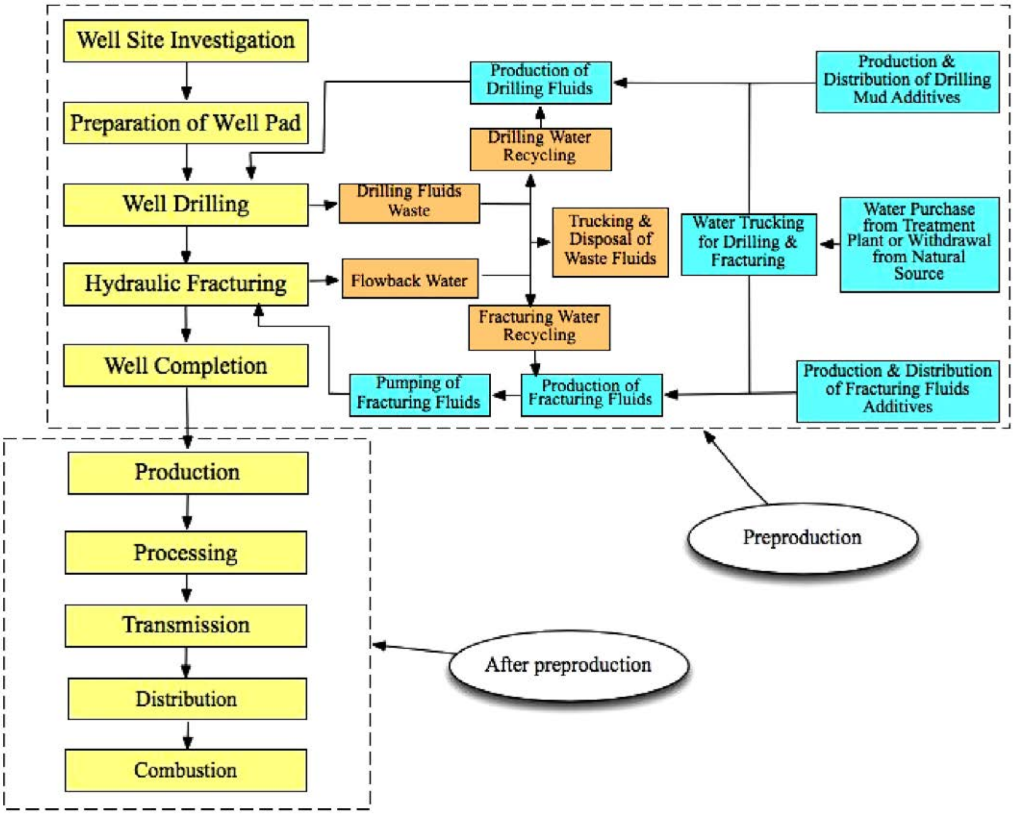

Figure 2. Analysis boundaries and gas production processes.

natural gas liquids before it enters the natural gas transmission and distribution system, which delivers it to final end users. For this work we assume that the GHG emissions for production, transmission, distribution and combustion of Marcellus shale natural gas are similar to average domestic gas sources as estimated by Jaramillo *et al* (2007) and further developed and updated by Venkatesh *et al* (2011).

Finally, natural gas has many current and potential uses including electricity generation, chemical feedstock, and as a transportation fuel. Modeling these uses allows comparisons of different primary energy sources. Here we model its use for power generation since it is the largest single use of natural gas in the US (US EIA 2011a, 2011b).

As previously mentioned, this study integrates GHG emissions from the life cycle of water associated with Marcellus shale gas production. Large amounts of water are consumed in the drilling and hydraulic fracturing processes (preproduction phase). Hydraulic fracturing uses fluid pressure to fracture the surrounding shale. The fracturing fluid consists of water mixed with a number of additives necessary to successfully fracture the shale seam. The source of the water varies and can be surface or ground water, purchased from a local public water supplier, or reused fracturing water. In this study we assume 45% of the water is reused on site and the original sources are surface water (50%) and purchased from a local water treatment plant (50%). Regardless of the water source used to produce the hydraulic fracturing fluid, trucks transport the water for impoundment at the well pad. In addition, flowback water (hydraulic fracturing fluid that returns to the surface) and produced water must be trucked to the final disposal site. This water is assumed to be disposed of via deep well injection. A detailed description of the method and data sources used to estimate the GHG emissions associated with all these stages is presented in section 3.

Marcellus shale gas production is in its infancy. Thus, industry practice is evolving and even single well longevity is unknown. Assumptions related to production rates and ultimate recovery have considerable uncertainty. Below, we include a sensitivity analysis for a wide range of inputs parameters.

This study does not consider any GHG emissions outside of the Marcellus shale gas preproduction and production processes. Natural processes or development actions such as hydraulic fracturing might lead to emissions of the shale gas external to a well, particularly in the case of poorly installed well casings (Osborn *et al* 2011). Any such external leaks are not included in this study.

3. Methods for calculating life cycle greenhouse gas emissions

Our study used a hybrid combination of process activity emission estimates and economic input–output life cycle assessment estimates to estimate the preproduction GHG emission estimates (Hendrickson *et al* 2006, CMU GDI 2010). Emissions from production, processing and transport were adapted from the literature. We include emissions estimates based on different data sources and reasonable

Table 1. Greenhouse gas estimation approaches and data sources.

Process	Estimation approaches	Data sources
Preparation of Well Pad:		
Vegetation clearing	Estimated area cleared multiplied by vegetative carbon storage to obtain carbon loss due to land use change	NY DEC (2009), Tilman *et al* (2006)
Well pad construction	Detailed cost estimate and EIO-LCA model	RSMeans (2005), CMU GDI (2010)
Well drilling:		
Drilling energy consumption	(1) Energy required and emission factor, and (2) cost estimate and EIO-LCA model	Harper (2008), Sheehan *et al* (2000), CMU GDI (2010)
Drilling mud production	(1) Cost estimate and EIO-LCA and (2) emission factors multiplied by quantity.	Shaker (2005), PRé Consultants (2007), CMU GDI (2010)
Drilling water consumption	Trucking emissions plus water treatment emissions multiplied by quantity	Wang and Santini (2009), URS Corporation (2010), PA DEP (2010), Stokes and Horvath (2006)
Hydraulic fracturing:		
Pumping	Pumping energy multiplied by emission factor	URS Corporation (2010), Kargbo *et al* (2010), Currie and Stelle (2010), Sheehan *et al* (2000)
Additives production	Additive quantities cost and EIO-LCA model	URS Corporation (2010), CMU GDI (2010)
Water consumption	Trucking emissions	Wang and Santini (2009), URS Corporation (2010), Stokes and Horvath (2006), PA DEP (2010)
Well completion:	If flaring, gas flow emission factor multiplied by flaring time	NY DEC (2009), PA DEP (2010)
Wastewater disposal:		
Deep well injection	Deep well injection costs and EIO-LCA model	US ACE (2006), CMU GDI (2010)
Production, processing, transmission and storage, and combustion	Assumed comparable to national average	Venkatesh *et al* (2011)

ranges of process parameters. Table 1 summarizes estimation approaches used in this study, while calculation details appear in the supplementary information (available at stacks.iop.org/ERL/6/034014/mmedia).

In section 3.1, we report point estimates of GHG emissions for a base case. In section 5, we report range estimates and consider the sensitivity of point estimates to particular assumptions. Table 2 summarizes important parameter assumptions and possible ranges. Uniform or triangular distributions are assigned to these parameters based on whether we had two (uniform) or three (triangular) data points. When more data was available, parameters of probability distributions that best fit the data were estimated. A Monte Carlo analysis was performed using these distributions, to estimate the emissions from the various activities considered in our life cycle model.

3.1. Emissions from Marcellus shale gas preproduction

Horizontal wells are drilled on a multi-well pad to achieve higher cost-effectiveness. It is reported that a Marcellus well pad might have as few as one well per pad and as many as 16, but more typically 6–8 (ICF International 2009, NY DEC 2009, Currie and Stelle 2010). As a base case scenario, we chose to analyze the typical pad with six wells, each producing 2.7 Bcf (3.0×10^9 MJ), representing an average of 0.3 MMcf per day of gas for 25 years. Other production estimates are higher. EQT (2011), for example, provides a production estimate of 7.3 Bcf (8.1×10^9 MJ) and Range Resources at 4.4 Bcf (4.9×10^9 MJ) (Ventura 2009). Within the LCA framework the impacts are distributed across the total volume of gas produced during the lifetime of the well. Thus, the choice of using the low end ultimate recovery as the base case should be considered conservative. With Marcellus shale gas production currently in its infancy, the average production characteristics have significant uncertainty, so we perform an

Table 2. Parameter assumptions and ranges. (Note: sources for base case and range values are in table 1 and discussed in the supplementary material (available at stacks.iop.org/ERL/6/034014/mmedia).)

Parameter	Base case	Range
Area of access road (acres)	1.43	0.1–2.75
Wells per pad (number)	6	1–16
Area of well pad (acres)	5	2–6
Vertical drilling depth (ft)	8500	7000–10 000
Horizontal drilling length (ft)	4000	2000–6000
Fracturing water (MMgal/well)	4	2–6
Flowback fraction (%)	37.5	35–40
Recycling fraction (%)	45	30–60
Trucking distance between well site and water source (miles)	5	0–10
Trucking distance between well site and deep well injection facility (miles)	80	3–280
Well completion time with collection system in place (h)	18	12–24
Well completion time without collection system in place (days)	9.5	4–15
Fraction of flaring (%)	76	51–100
Initial 30 day gas flow rate (MMscf/day)	4.1	0.7–10
Average well production rate (MMscf/day)	0.3	0.3–10
Well lifetime (years)	25	5–25

extensive sensitivity analysis over a range of flow rates and well lifetimes, as discussed below.

The EIO-LCA (CMU GDI 2010) model was used to estimate GHG emissions from the construction of the access road and the multi-well pad. These costs were estimated using the utility price cost estimation method (RSMeans 2005). The size of an average Marcellus well pad is reported as being between 2 and 6 acres and typically between 4 and 5 acres (16 000 and 20 000 m^2) during drilling and fracturing phase (NY DEC 2009, Columbia University 2009). The costs of constructing this pad are estimated to be \$3.0–\$3.3 million per well pad in 2002 dollars (see the supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail). Using these costs as input, GHG emissions associated with well pad construction are estimated with the EIO-LCA (CMU GDI 2010) model.

Greenhouse gas emissions associated with drilling operations were calculated by two methods; (1) using the drilling energy intensity (table 1) and the life cycle diesel engine emissions factor of 635 g CO_2e per hp–hr output (Sheehan *et al* 2000), and (2) using drilling cost data and the EIO-LCA model (CMU GDI 2010). The EIA estimated the average drilling cost for natural gas wells in 2002 to be \$176 per foot (including the cost for drilling and equipping the wells and for surface producing facilities) (US EIA 2008). Emissions associated with the production of the drilling mud components were based on data from the SimaPro life cycle tool and the EIO-LCA economic model (PRé Consultants 2007, CMU GDI 2010).

Hydraulic fracturing associated GHG emissions result from the operation of the diesel compressor used to move and compress the fracturing fluid to high pressure, the emissions associated with the production of the hydraulic fracturing fluid, and from fugitive methane emissions as flowback water is captured. The last category of emissions is discussed separately below. Energy and emissions associated with the hydraulic fracturing process were modeled by using vendor specific diesel data along with the emission factor described above. The emissions of hydraulic fracturing fluid production are estimated with EIO-LCA model, based on the price of additives and fracturing fluid composition (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail).

There may be significant GHG emissions as a result of flaring and venting activities that occur during well casing and gathering equipment installation. The natural gas associated with the hydraulic fracturing flowback water is flared and vented. Flaring is used for testing the well gas flow prior to the construction of the gas gathering system which transport the gas to the sales line. Well completion emissions depend on the flaring/venting time, gas flow rate during well completion, the ratio of flaring to venting, and flaring efficiency. Uncertainty/variability analysis was conducted to investigate the effect of flaring/venting time, gas flow rate during fracturing water flowback, and flaring per cent on the well completion emissions. For those well completions with the collection facilities in place, gas is flared for between 12 and 24 h, due to necessary flowback operations. In wells where the appropriate gas gathering system as a tie to the gas sales line is not available for the gas during fracturing water flowback, the flaring or venting can occur for between 4 and 15 days as shown in table 2 (NY DEC 2009). In our model, we assumed the gas release rate during well completion equals the initial 30 day gas production rate for the base case and considered a scenario with both venting and flaring (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for details).

3.2. Emissions from Marcellus shale gas production to combustion

GHG emissions for production, processing, transmission, distribution and combustion of Marcellus shale natural gas are assumed to be similar to the US average domestic gas system that have been estimated previously (Jaramillo *et al* 2007). Jaramillo *et al* (2007) estimates were updated to include the uncertainty and variability in life cycle estimates and recalculated with recent and/or more detailed information by Venkatesh *et al* (2011). The GHG emissions from these life cycle stages consist of vented methane (gas release during operation), fugitive methane (unintentional leaks) and CO_2 emissions from the processing plants and from fuel consumption. Methane leakage rates throughout the natural gas system (excluding the preproduction processes previously discussed) are a major concern and our analysis has an implied fugitive emissions rate of 2%, consistent with the EPA natural gas industry study (US EPA 1996, 2010).

Venkatesh *et al* (2011) estimated the mean emission factors used in this study: 9.7 g CO_2e/MJ of natural gas in production; 4.3 g CO_2e MJ for processing; 1.4 g CO_2e/MJ for transmission and storage; 0.8 g CO_2e/MJ for distribution; and 50 g CO_2e/MJ for combustion.

3.3. Emissions associated with the life cycle of water used for drilling and hydraulic fracturing

Water resource management is a critical component of the production of Marcellus shale natural gas. Chesapeake Energy (2010) indicates that 100 000 gallons of water are used for drilling mud preparation. Two to six million gallons of water per well are required for the hydraulic fracturing process (Staaf and Masur 2009). About 85% of the drilling mud is reused (URS Corporation 2010). The flowback and recycling rates are used to estimate the total volume of water required. About 60–65% of this hydrofracturing fluid is recovered (URS Corporation 2010). For the flowback water, a recycle rate from 30 to 60% can be achieved (Agbaji *et al* 2009). The rest of the flowback water is temporarily stored in the impoundment and transported off site for disposal. Base case assumptions for these parameters are shown in table 2.

Emissions associated with drilling water use and hydraulic fracturing water use result from water taken from surface water resources or a local public water system; truck transport to the well pad, and then from the pad to disposal via deep well injection. It is assumed that no GHG emissions are related

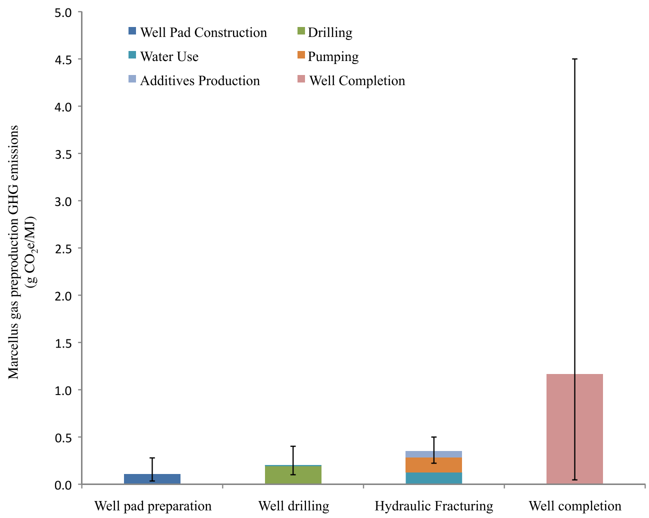

Figure 3. GHG emissions from different stages of Marcellus shale gas preproduction.

with producing water if it comes from surface water resources. For the water purchased from a local public water system, the emission factor for water treatment is used, which is estimated to be 3.4 g CO_2e/gallon of water generated according to Stokes and Horvath (2006). The energy intensity for transportation of liquids via truck is assumed to be 1028 Btu/ton mile for both forward and back-haul trips, as given in the GREET model (Wang and Santini 2009). In this study we assume that separate round trips are needed to transport the freshwater to the pad and to remove wastewater to the disposal site. This is to say that trucks bring in the freshwater from the source and return to the source empty; trucks also collect the wastewater from the well site and return to the well site empty. The life cycle emission factor (wells to wheels) for diesel as a transportation fuel is 93 g CO_2e/MJ (Wang and Santini 2009).

To estimate transport emissions associated with water taken from surface streams and water purchased from the local public water system, we used spatial analysis (ArcGIS) to estimate the distance from the surface water source to the well pad using well operational data and geographical information from Pennsylvania Department of Environmental Protection (2010). We depicted the overall distribution pattern of Marcellus wells under drilling and production in PA and NY in June 2010 by GIS. The distance from the well site to the surface water source is assumed to be 5 miles or 8 km in the base case of the model and the same transportation distance is also assumed for the water purchased from local public water system. We assumed an equal probability for sourcing water between surface water and the local public water system.

The trucking distance between well site and deep well injection facility was also estimated by GIS (PA DEP 2010). The average value of 80 miles or 130 km as determined by GIS was used in the base case.

4. Results for the base case

A total of 5500 t CO_2e is emitted during 'preproduction' per well. This is equivalent to 1.8 g CO_2e/MJ of natural gas produced over the lifetime of the well. Figure 3 depicts the GHG emissions by preproduction stage and by source. As can be seen, the completion stage has the largest GHG emissions, which result from flaring and/or venting. The error bars represent the limits of the 90% confidence interval of the emissions from each stage based on the uncertainty analysis.

A recent EPA report addressing emissions from the natural gas industry reported that 177 t of CH_4 is released during the completion of an unconventional gas well (US EPA 2010). This estimate is consistent with the analysis here and falls within the range estimated by our study, 26–1000 t of CH_4 released per completion and a mean value of 400 t of CH_4 released per completion. In our model, this methane released during the well completion is either flared with a combustion efficiency of 98% or vented without recovery.

Adding the preproduction emissions estimate to the downstream emission estimated by Venkatesh *et al* (2011) results in an overall GHG emissions factor of 68 g CO_2e/MJ of gas produced (figure 4). The life cycle emissions are dominated by combustion that accounts for 74% of the total emissions.

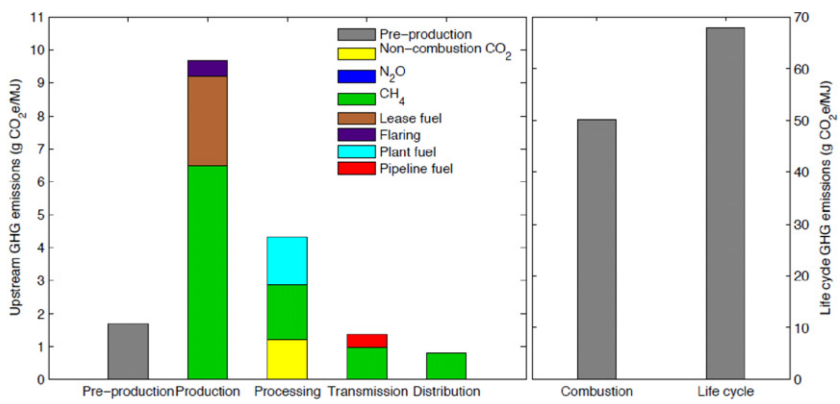

Figure 4. GHG emissions through the life cycle of Marcellus shale gas. (Preproduction through distribution emissions are on left scale; combustion and total life cycle emissions are on right scale. No carbon capture is included after combustion.)

Table 3. Uncertainty analysis on Marcellus gas preproduction.

Life cycle stage	Mean ($g\ CO_2e/MJ$)	Standard deviation ($g\ CO_2e/MJ$)	COV	90% CI-L (%)	90% CI-U (%)
Well pad preparation	0.13	0.1	0.72	58	131
Drilling	0.21	0.1	0.50	51	95
Hydraulic fracturing	0.35	0.1	0.24	37	42
Completion	1.15	1.8	1.53	96	287
Total	1.84	1.8	0.96	67	179

Table 4. Sensitivity of emissions from wells with different production rates and lifetimes. (Source: author calculations.)

Average gas flow (MMscf/day)	Lifetime (years)	Emissions from preproduction ($g\ CO_2e/MJ$)	Preproduction % contribution to life cycle emissions of Marcellus shale gas (%)	Total life cycle emissions ($g\ CO_2e/MJ$)
10	25	0.1	0.1	65.3
10	10	0.1	0.2	65.3
10	5	0.3	0.4	65.5
3	25	0.2	0.3	65.4
3	10	0.5	0.7	65.7
3	5	0.9	1.4	66.1
1	25	0.6	0.8	65.8
1	10	1.4	2.1	66.6
1	5	2.8	4.1	68.0
0.3	25	1.8	2.7	67.0
0.3	10	5	6.6	69.8
0.3	5	9.2	12.4	74.4

5. Sensitivity and uncertainty

Our results are subject to considerable uncertainty, particularly for the production rates and well lifetime. Table 3 summarizes the uncertainty analysis on the emission estimates for preproduction based on the distribution of parameters used.

Table 4 addresses model sensitivity to different estimates of ultimate gas recovery from wells, investigating the impact of different production rates and lifetimes. At high production rates and long well lifetimes the preproduction GHG emissions are normalized over higher volumes of natural gas than when using low flow rates and short well lifetimes. Comparing the case of 10 MMscf/day with a 25-year well lifetime to 0.3 MMscf/day with a 5-year well lifetime, table 4 shows that the emissions go from 0.1 to 9.2 g CO_2e/MJ. The overall life cycle emissions change from 65 to 74 g CO_2e/MJ. However, the preproduction emissions are less than 15% of the total life cycle emissions in all cases.

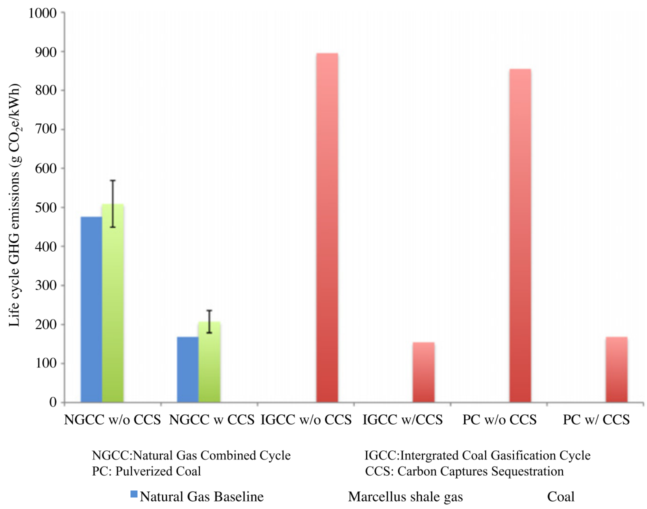

Figure 5. Comparison of life cycle GHG emissions from current domestic natural gas, Marcellus shale gas and coal for use in electricity production.

6. Comparison with coal for power generation

Marcellus shale gas emissions can be compared to alternative energy sources and processes when using a common metric such as electricity generated. Currently coal power plants are used to generate base load. Natural gas power plants, especially inefficient ones, are used to provide regulation services to balance supply and demand at times when base load power plants are insufficient or there is high-frequency variability in load or from renewable resources. Natural gas combined cycle (NGCC) plants could be used to generate base load thus competing directly with coal to provide this service. For this reason our comparison includes the emissions associated with using Marcellus shale gas in a NGCC power plant (efficiency of 50%) and the emissions from using coal in pulverized coal (PC) plants (efficiency of 39%) and integrated gasification combined cycle (IGCC) plants (efficiency of 38%). The results of these comparisons can be seen in figure 5. For this comparison point values are used for the life cycle GHG emissions of coal-based electricity. The error bars found in figure 5 represent the low and high emissions values for Marcellus shale gas, based on the assumptions of well production rate and well lifetime. The high-emission scenario assumes a 5-year well with 0.3 MMscf/day production rate while the low-emission scenario, assumes a 25-year well with 10 MMscf/day production rate. Also shown in figure 5 are the life cycle emissions of electricity generated in power plants with carbon capture and sequestration (CCS) capabilities (efficiency of 43% for NGCC with CCS; efficiency of 30% for PC with CCS; efficiency of 33% for ICGG with CCS).

In general, natural gas provides lower greenhouse emission for all cases studied whether the gas is derived from Marcellus shale or the average 2008 domestic natural gas system. When advanced technologies are used with CSS then the emissions are similar and coal provides slightly less emissions. This implies that the upstream emissions for natural gas life cycle are higher than the upstream emissions from coal, once efficiencies of power generation are taken into account (Jaramillo *et al* 2007).

The comparison of natural gas and coal for electricity allows us to investigate the impact of three additional model uncertainty components including the choice of leakage rate, GWP values, and re-refracking of a Marcellus gas well. This study assumes a 2% production phase leakage rate based on the volume of gas produced (US EPA 2010, Venkatesh *et al* 2011). Assuming the average efficiency of 43% for natural gas fired electricity generation and 32% for coal fired plants the fugitive emissions rate would need to be 14% (resulting in a life cycle emission factor for Marcellus gas of 125 g CO_2e/MJ) before the overall life cycle emissions including those of electricity generation would be greater than coal. This is an exorbitantly high leakage rate and to put it into perspective, using 2009 dry natural gas production estimates and the average wellhead price, we calculate that the economic losses a would total around $11 billion. If we convert our data to the 20-year GWP the break-even point is reduced to 7% because of the higher impacts attributed to methane. Finally, we modeled a single hydraulic fracturing event occurring during well preproduction (figure 3). Above we calculated that the break-even emission factor that would make coal and natural electricity generation the same is 125 g CO_2e/MJ of natural gas. With the current emissions estimate for Marcellus gas of 68 g CO_2e/MJ, and a hydraulic fracturing event (and its associated flaring and venting emissions) contributing 1.5 g CO_2e/MJ to this estimate, more than 25 fracturing events would need to occur in a single well before the decision between coal and natural gas would change.

7. Comparison with liquefied natural gas as a future source

In 2005 EIA suggested that domestic natural gas production and Canadian imports would decline as natural gas consumption increased. EIA predicted that liquefied natural gas (LNG) imports would grow to offset the deficits in North American production (US EIA 2011a, 2011b). As a result of the development of unconventional natural gas reserves, EIA has changed their projections. The Annual Energy Outlook 2011 reference case (US EIA 2011a, 2011b) predicts that increases in shale gas production, including Marcellus, will more than offset the decline in conventional natural gas and decreasing imports from Canada and will allow for increases in natural gas consumption. Since shale gas is projected to be the largest component of the unconventional sources of future natural gas production, it seem appropriate to compare its emissions to those of the gas that would be used if shale gas were not produced. Venkatesh *et al* (2011) estimated the life cycle GHG from LNG imported to the US to have a mean of 70 g CO_2e/MJ, These results are based on emissions due to production and liquefaction in the countries of origin, shipping the gas to the US by ocean tanker, regasification in the US and its transmission, distribution and subsequent combustion. On average, the emissions of Marcellus shale gas were about 3% lower than LNG. As with the overall Marcellus gas results, there is considerable uncertainty to the comparisons. However, we conclude that as these unconventional sources of natural gas supplant LNG imports, overall emissions will not rise.

8. Conclusion

The GHG emission estimates shown here for Marcellus gas are similar to current domestic gas. Other shale gas plays could generate different results considering regional environmental variability and reservoir heterogeneity. Green completion and capturing the gas for market that would otherwise be flared or vented, could reduce the emissions associated with completion and thus would significantly reduce the largest source of emissions specific to Marcellus gas preproduction. These preproduction emissions, however, are not substantial contributors to the life cycle estimates, which are dominated by the combustion emissions of the gas. For comparison purposes, Marcellus shale gas adds only 3% more emissions to the average conventional gas, which is likely within the uncertainty bounds of the study. Marcellus shale gas has lower GHG emissions relative to coal when used to generate electricity.

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States

Timothy J. Skone, P.E.

Office of Strategic Energy Analysis and Planning

May 12, 2011

Presented at: Cornell University Lecture Series

U.S. DEPARTMENT OF ENERGY

Overview

1. **Who is NETL?**
2. **What is the role of natural gas in the United States?**
3. **Who uses natural gas in the U.S.?**
4. **Where does natural gas come from?**
5. **What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?**
6. **How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?**
7. **What are the opportunities for reducing GHG emissions?**

<u>Question #1:</u>

Who is NETL?

National Energy Technology Laboratory

MISSION
Advancing energy options to fuel our economy, strengthen our security, and improve our environment

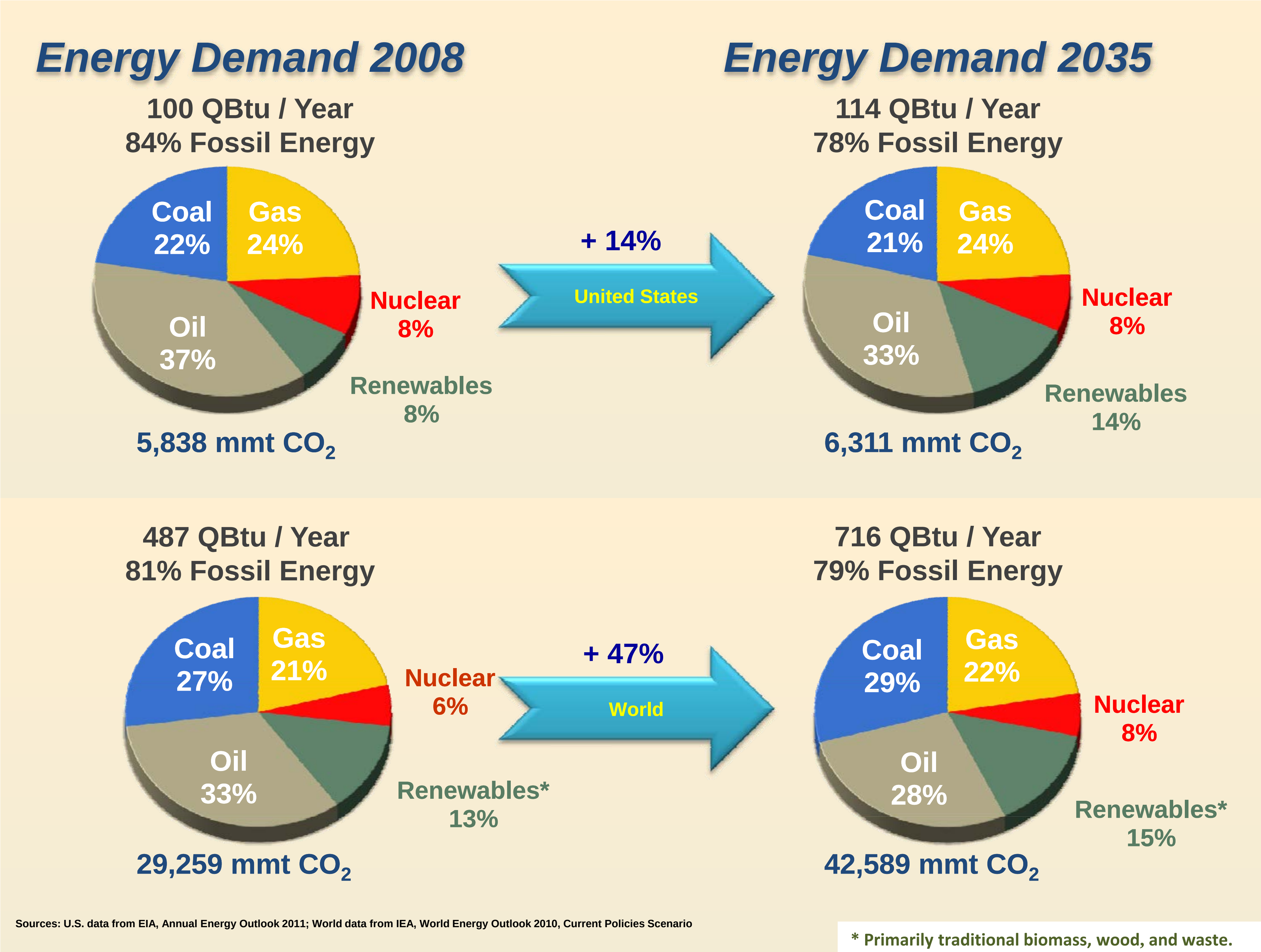
Oregon

Pennsylvania

West Virginia

<u>Question #2:</u>

What is the role of natural gas in the United States?

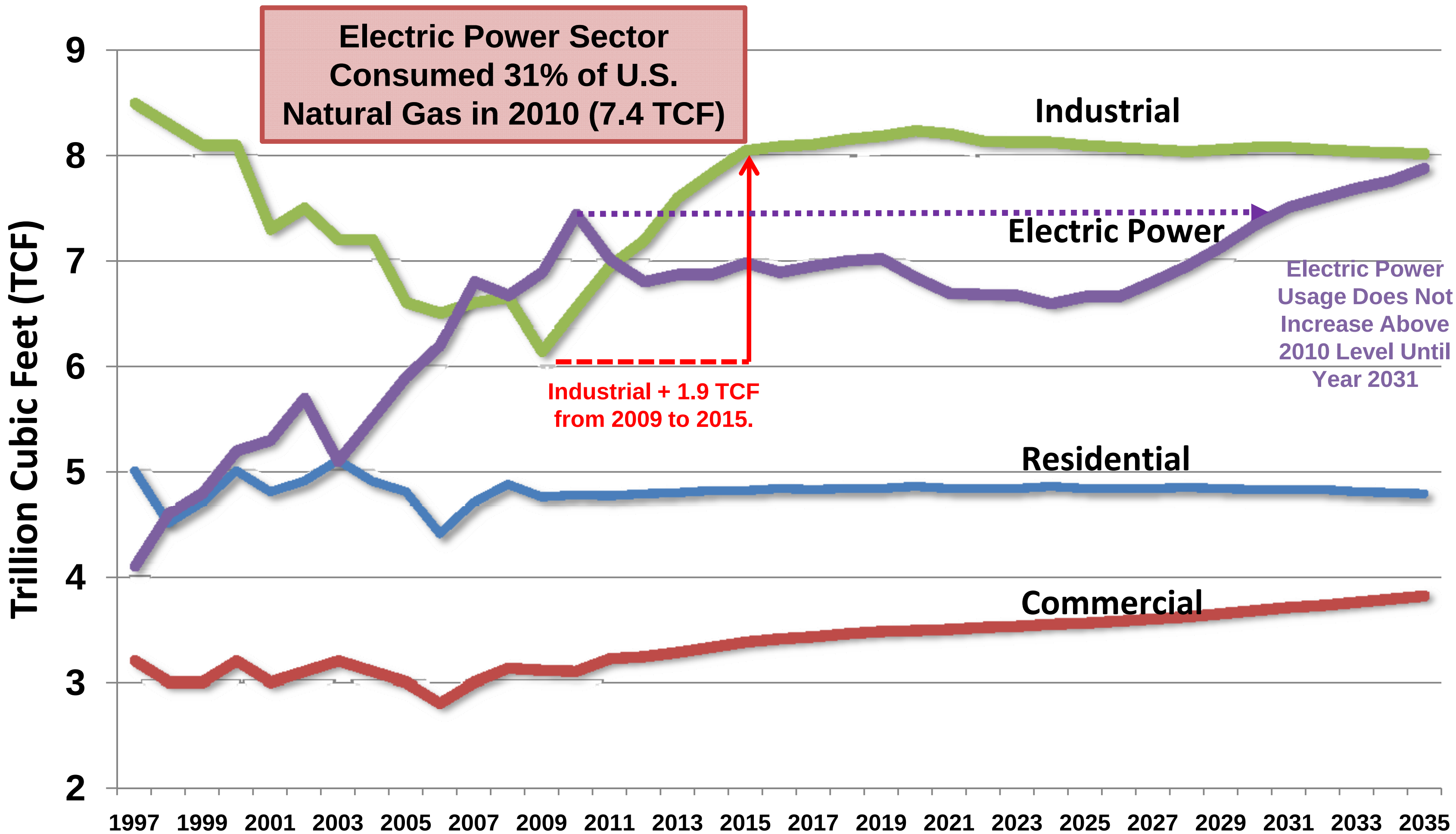

Energy Demand 2008
100 QBtu / Year
84% Fossil Energy
Coal 22%
Gas 24%
Nuclear 8%
Renewables 8%
Oil 37%
5,838 mmt CO_2
+ 14%
United States
Energy Demand 2035
114 QBtu / Year
78% Fossil Energy
Coal 21%
Gas 24%
Nuclear 8%
Renewables 14%
Oil 33%
6,311 mmt CO_2
487 QBtu / Year
81% Fossil Energy
Coal 27%
Gas 21%
Nuclear 6%
Renewables* 13%
Oil 33%
29,259 mmt CO_2
+ 47%
World
716 QBtu / Year
79% Fossil Energy
Coal 29%
Gas 22%
Nuclear 8%
Renewables* 15%
Oil 28%
42,589 mmt CO_2
Sources: U.S. data from EIA, Annual Energy Outlook 2011; World data from IEA, World Energy Outlook 2010, Current Policies Scenario
* Primarily traditional biomass, wood, and waste.

Question #3:

Who uses natural gas in the United States?

Domestic Natural Gas Consumption

Sectoral Trends and Projections: 2010 Total Consumption = 23.8 TCF



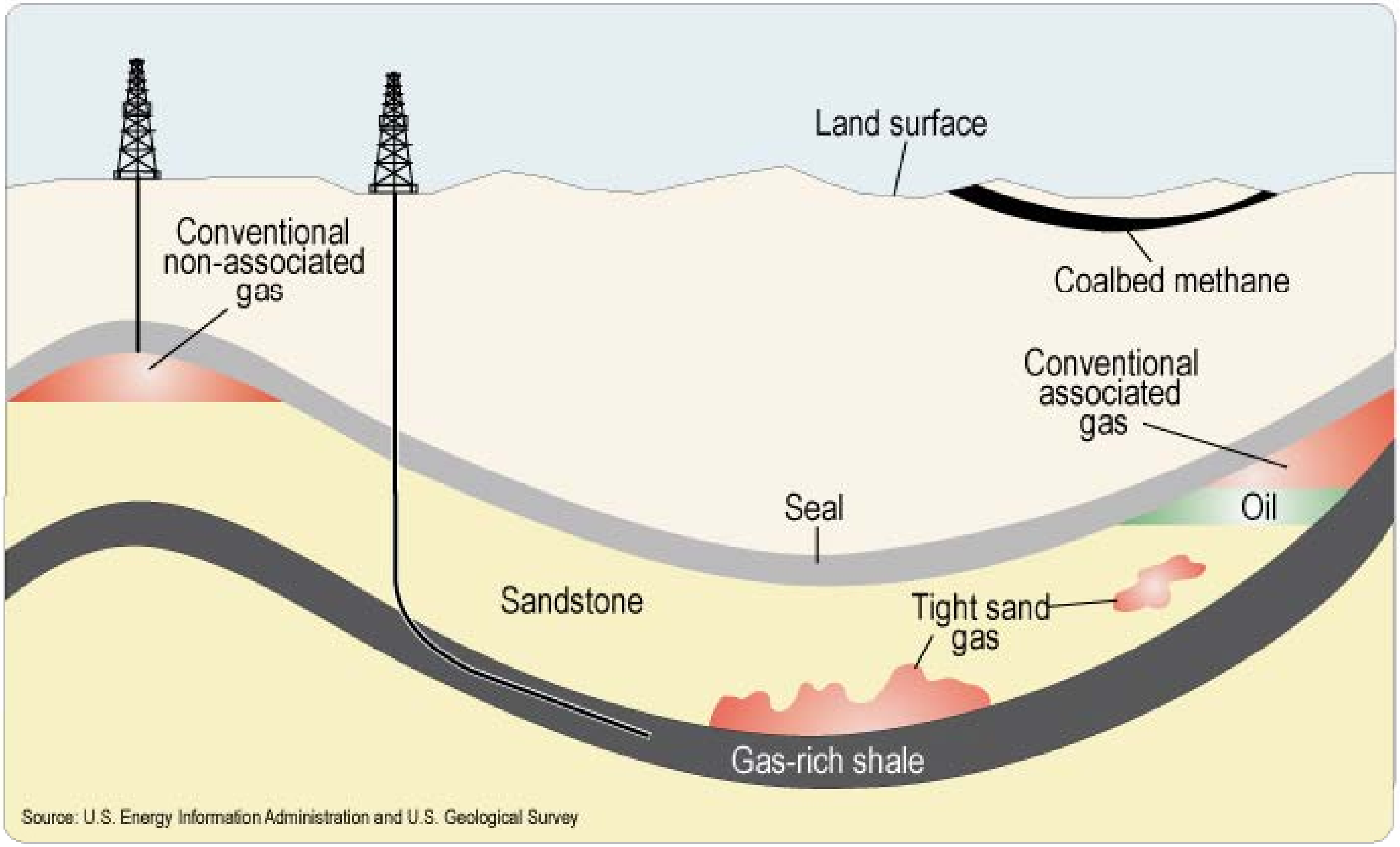
+1.9 TCF Resurgence in Industrial Use of Natural Gas by 2015 Exceeds the Net Incremental Supply; No Increase in Natural Gas Use for Electric Power Sector Until 2031

Source: EIA Annual Energy Review 2009 and Annual Energy Outlook 2011

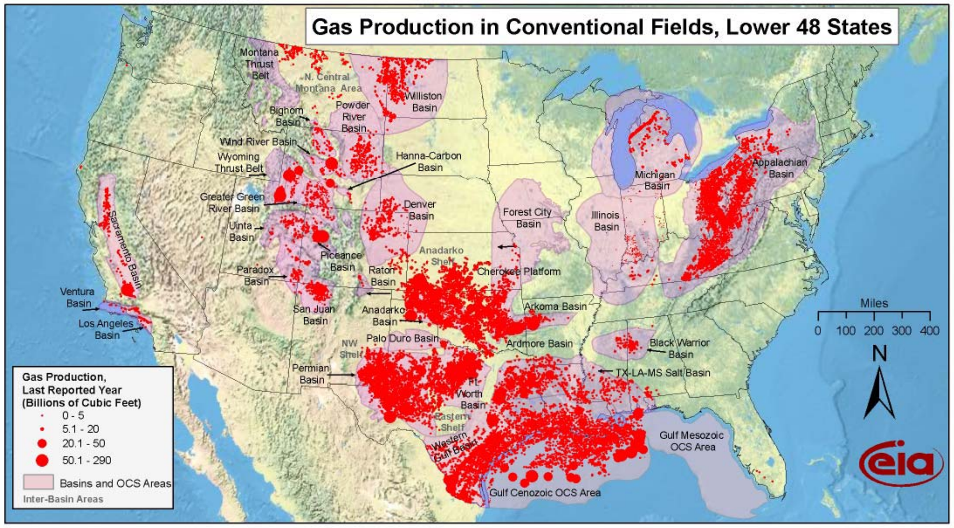
Question #4:

Where does natural gas come from?

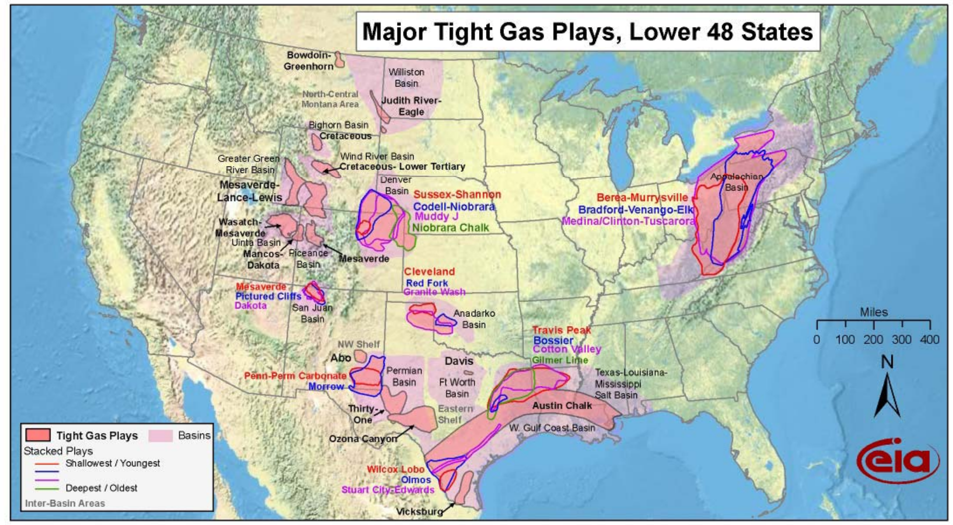
Schematic Geology of Onshore Natural Gas Resources



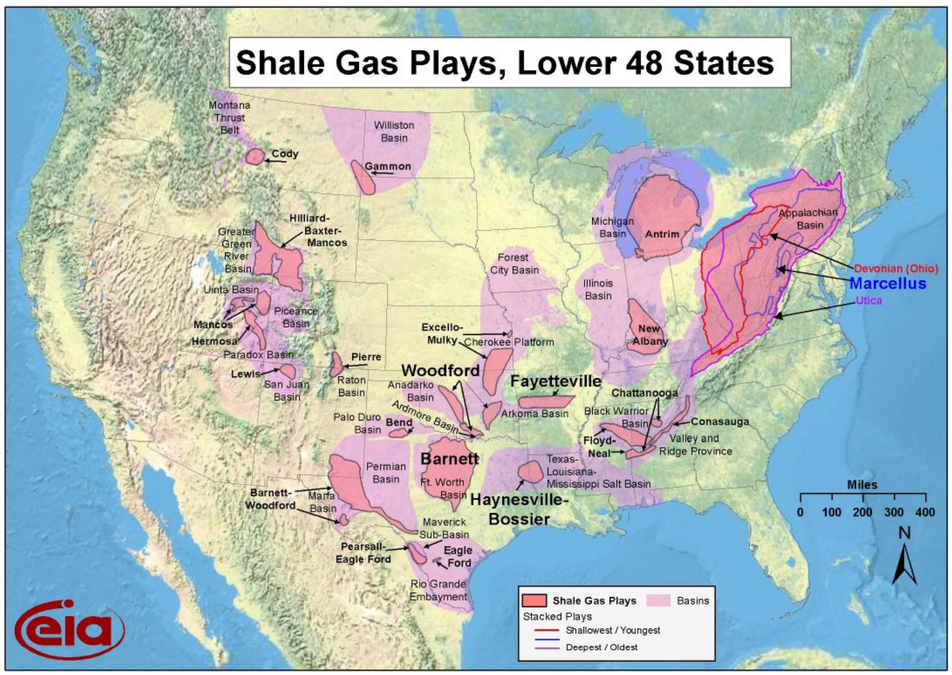
Source: EIA, Today in Energy, February 14, 2011; Modified USGS Figure from Fact Sheet 0113-01; www.eia.doe.gov/todayinenergy/detail.cfm?id=110 Last Accessed May 5, 2011.



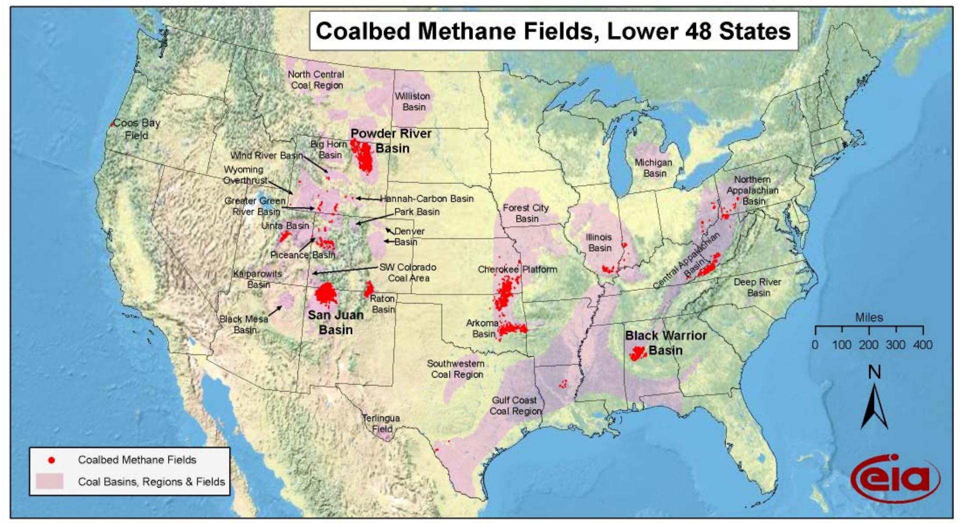
Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009



Source: Energy Information Administration based on data from various published studies
Updated: June 6, 2010



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010



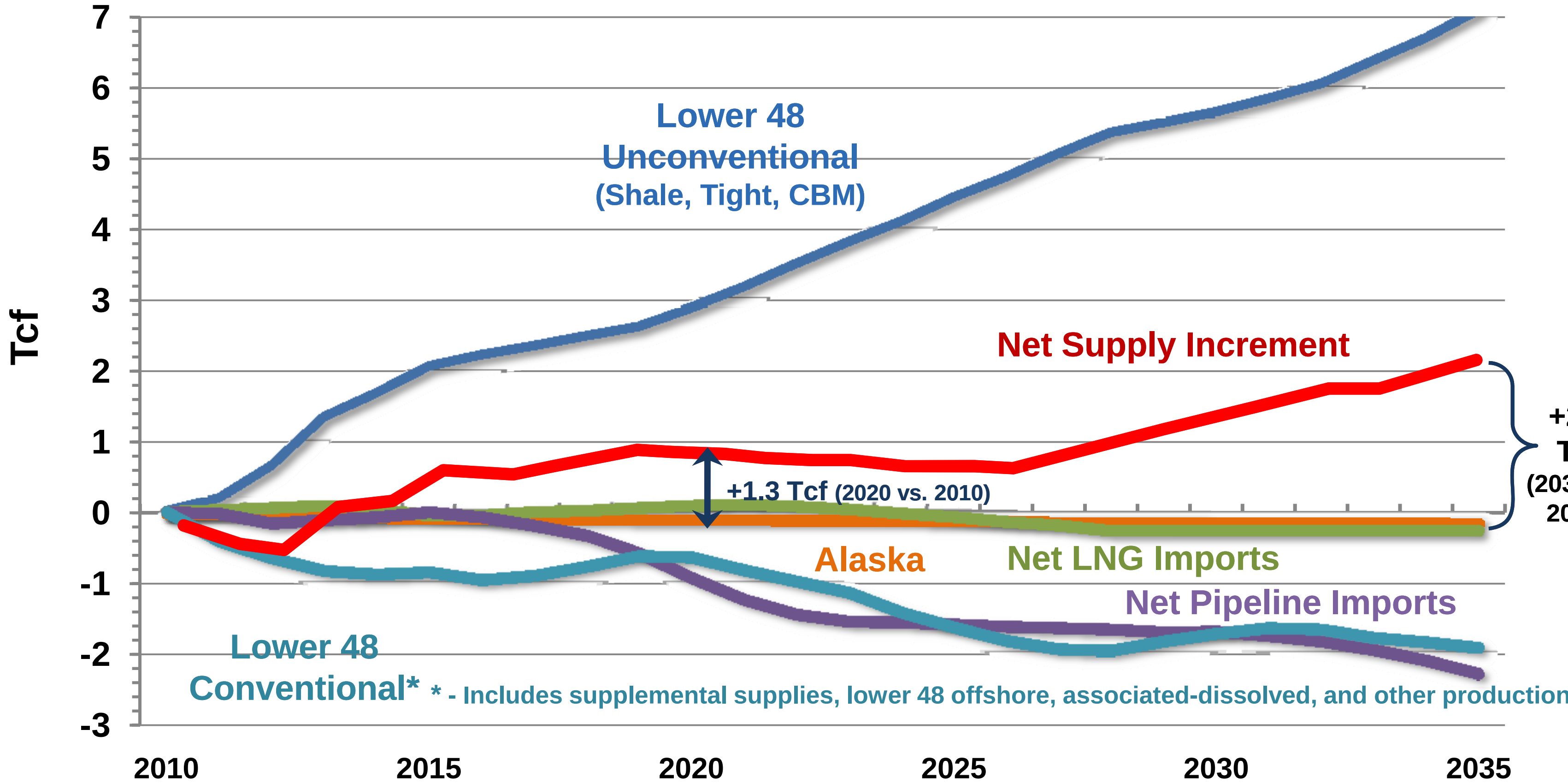
Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

EIA Natural Gas Maps

Source: EIA, Natural Gas Maps, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm Last Accessed May 5, 2011.

Sources of Incremental Natural Gas Supply

(Indexed to 2010)



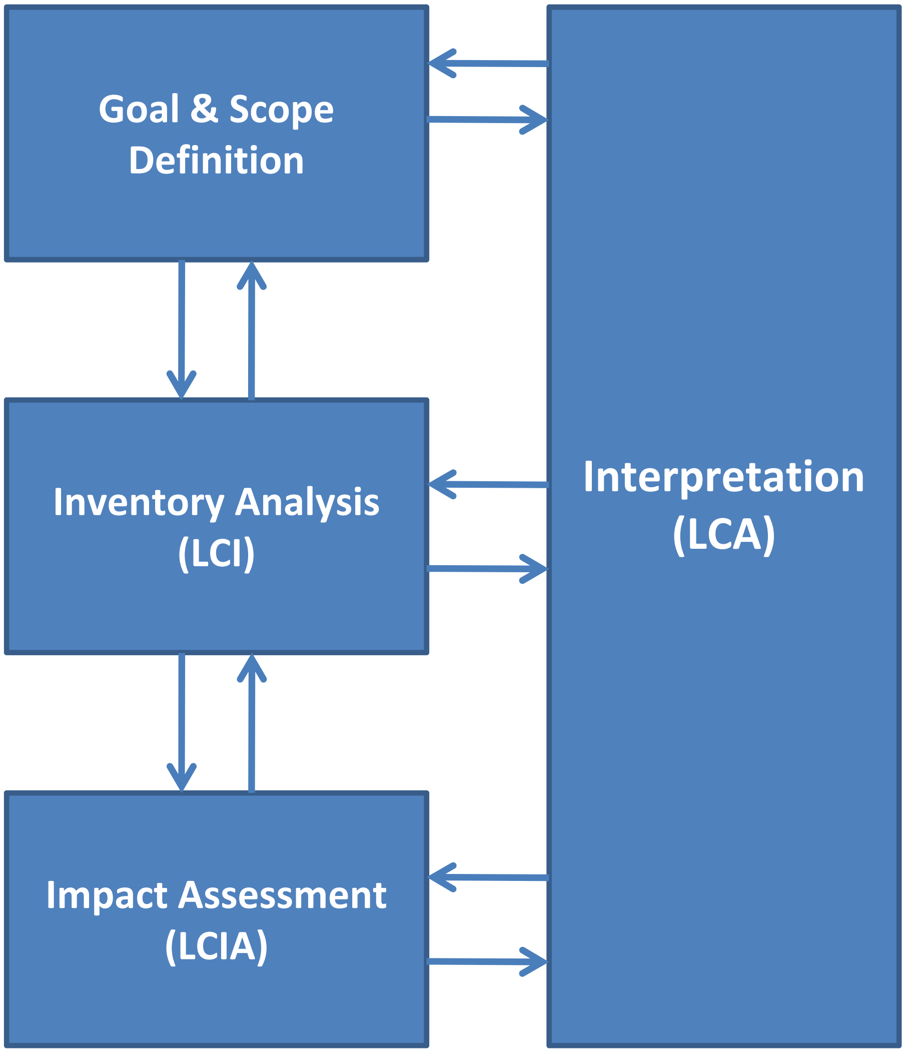
Unconventional Production Growth Offset by Declines in Conventional Production and Net Pipeline Imports; 1.3 Tcf Increment by 2020 Does Not Support Significant Coal Generation Displacement

Source: EIA, Annual Energy Outlook 2011

Question #5:

What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?

Overview: Life Cycle Assessment Approach



Source: ISO 14040:2006, Figure 1 – Stages of an LCA (reproduced)

The Type of LCA Conducted Depends on Answers to these Questions:

1. What Do You Want to Know?

2. How Will You Use the Results?

International Organization for Standardization (ISO) for LCA

- ISO 14040:2006 Environmental Management – Life Cycle Assessment – Principles and Framework
- ISO 14044 Environmental Management – Life Cycle Assessment – Requirements and Guidelines
- ISO/TR 14047:2003 Environmental Management – Life Cycle Impact Assessment – Examples of Applications of ISO 14042
- ISO/TS 14048:2002 Environmental Management – Life Cycle Assessment – Data Documentation Format

Overview: Life Cycle Assessment Approach

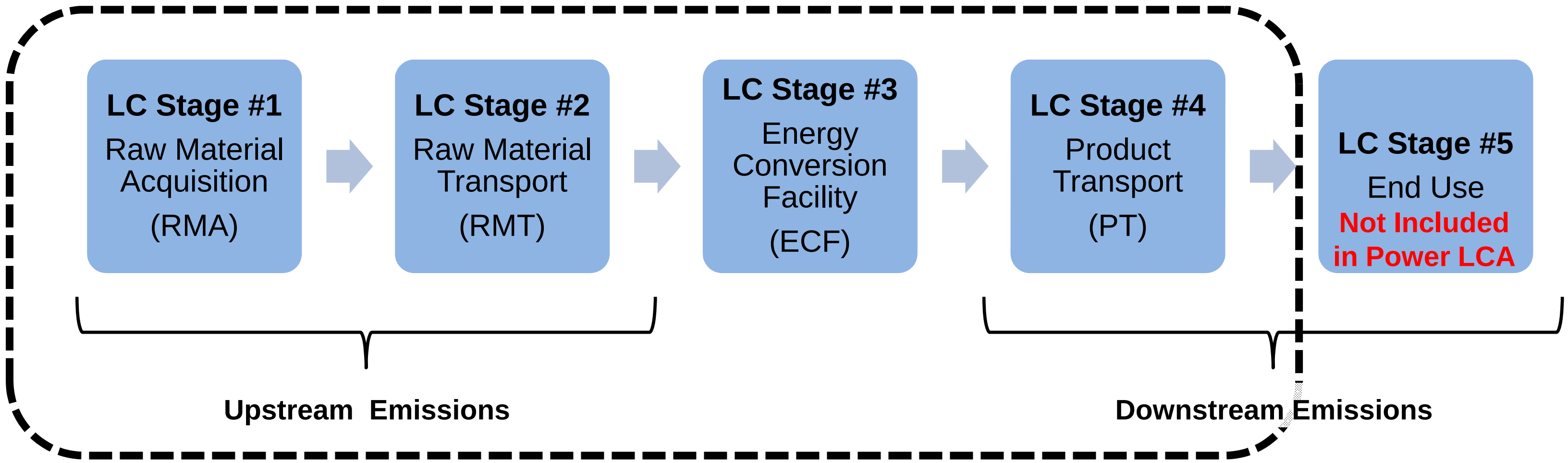
The Type of LCA Conducted Depends on Answers to these Questions :

1. **What Do You Want to Know?**
   - ❑ **The GHG footprint of natural gas, lower 48 domestic average, extraction, processing, and delivery to a large end-user (e.g., power plant)**
   - ❑ **The comparison of natural gas used in a baseload power generation plant to baseload coal-fired power generation on a lbs CO_2e/MWh basis**

2. **How Will You Use the Results?**
   - ❑ **Inform research and development activities to reduce the GHG footprint of both energy feedstock extraction and power production in existing and future operations**

NETL Life Cycle Analysis Approach

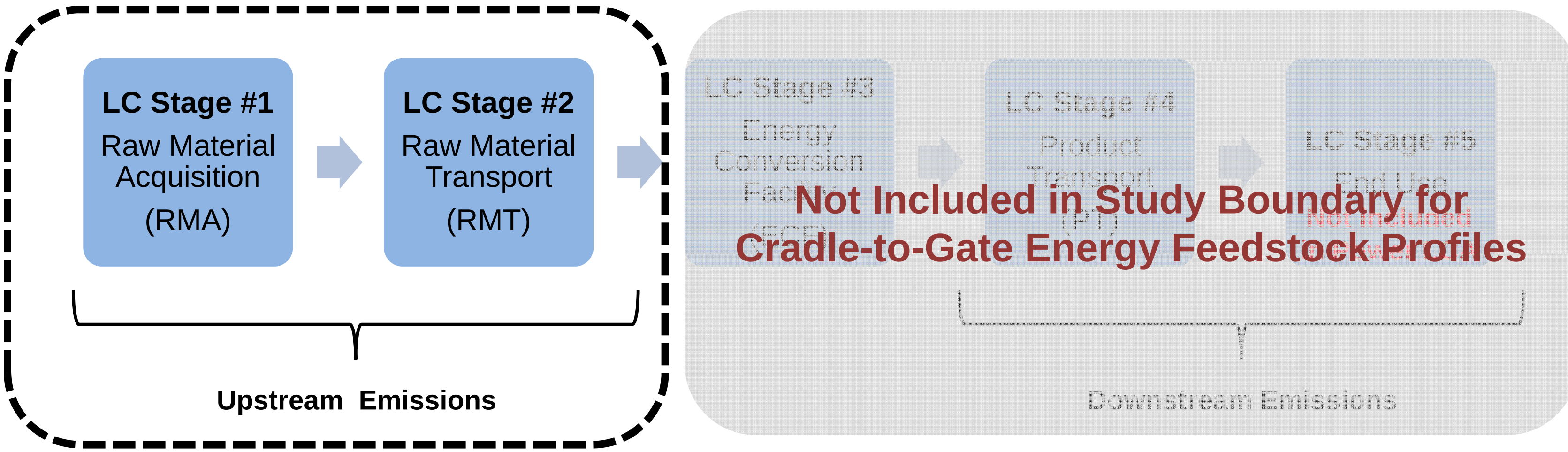
- **Compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product or service throughout its life cycle, from raw material acquisition to the final disposal**



- **The ability to compare different technologies depends on the functional unit (denominator); for power LCA studies:**
  – 1 MWh of electricity delivered to the end user

NETL Life Cycle Analysis Approach for Natural Gas Extraction and Delivery Study

- **The study boundary for "domestic natural gas extraction and delivery to large end-users" is represented by Life Cycle (LC) Stages #1 and #2 only.**



- **Functional unit (denominator) for energy feedstock profiles is:**
  – 1 MMBtu of feedstock delivered to end user
    (MMBtu = million British thermal units)

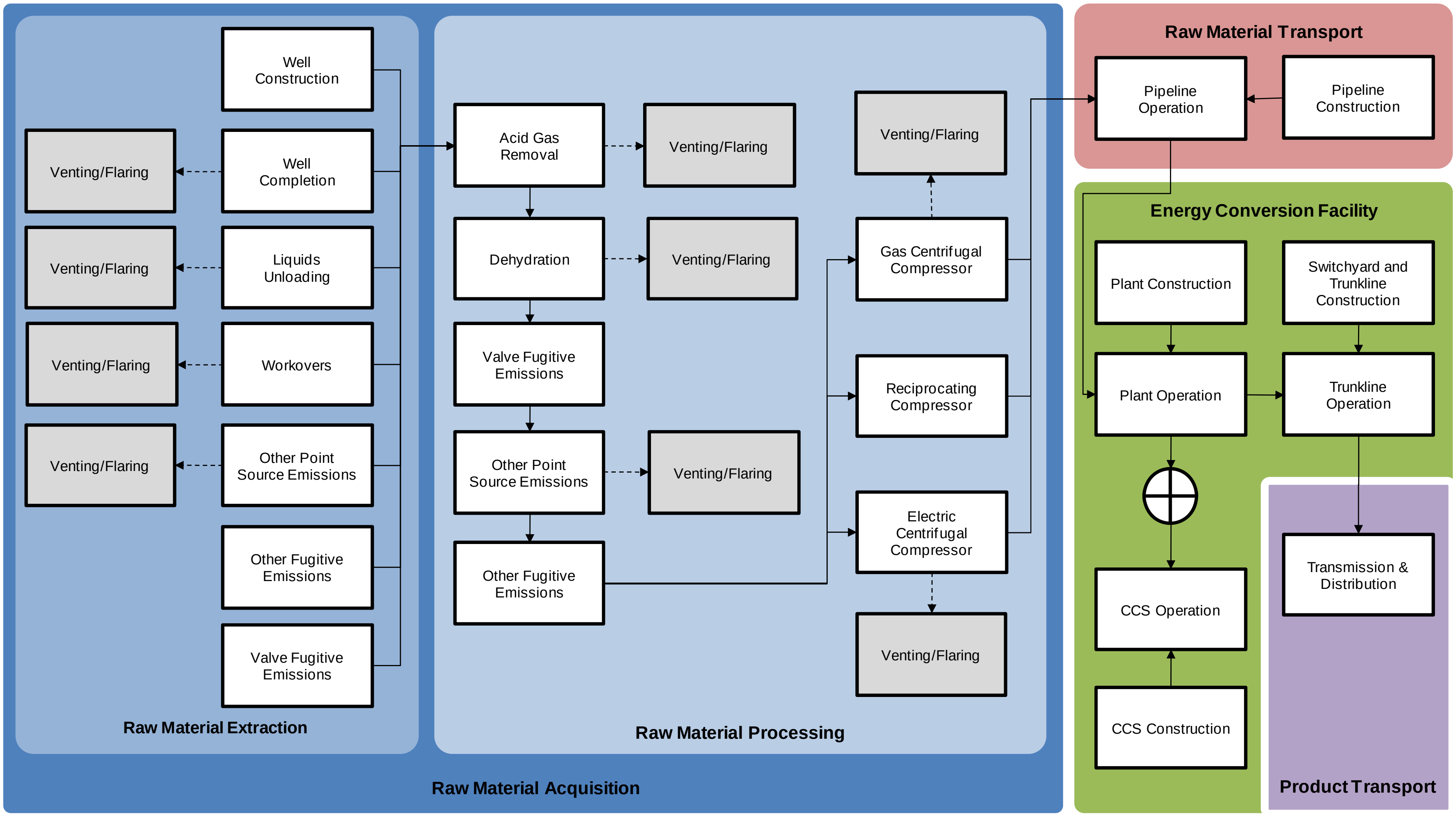
NETL Life Cycle Study Metrics

- **Greenhouse Gases**
  - CO_2, CH_4, N_2O, SF_6
- **Criteria Air Pollutants**
  - NO_X, SO_X, CO, PM10, Pb
- **Air Emissions Species of Interest**
  - Hg, NH_3, radionuclides
- **Solid Waste**
- **Raw Materials**
  - Energy Return on Investment
- **Water Use**
  - Withdrawn water, consumption, water returned to source
  - Water Quality
- **Land Use**
  - Acres transformed, greenhouse gases

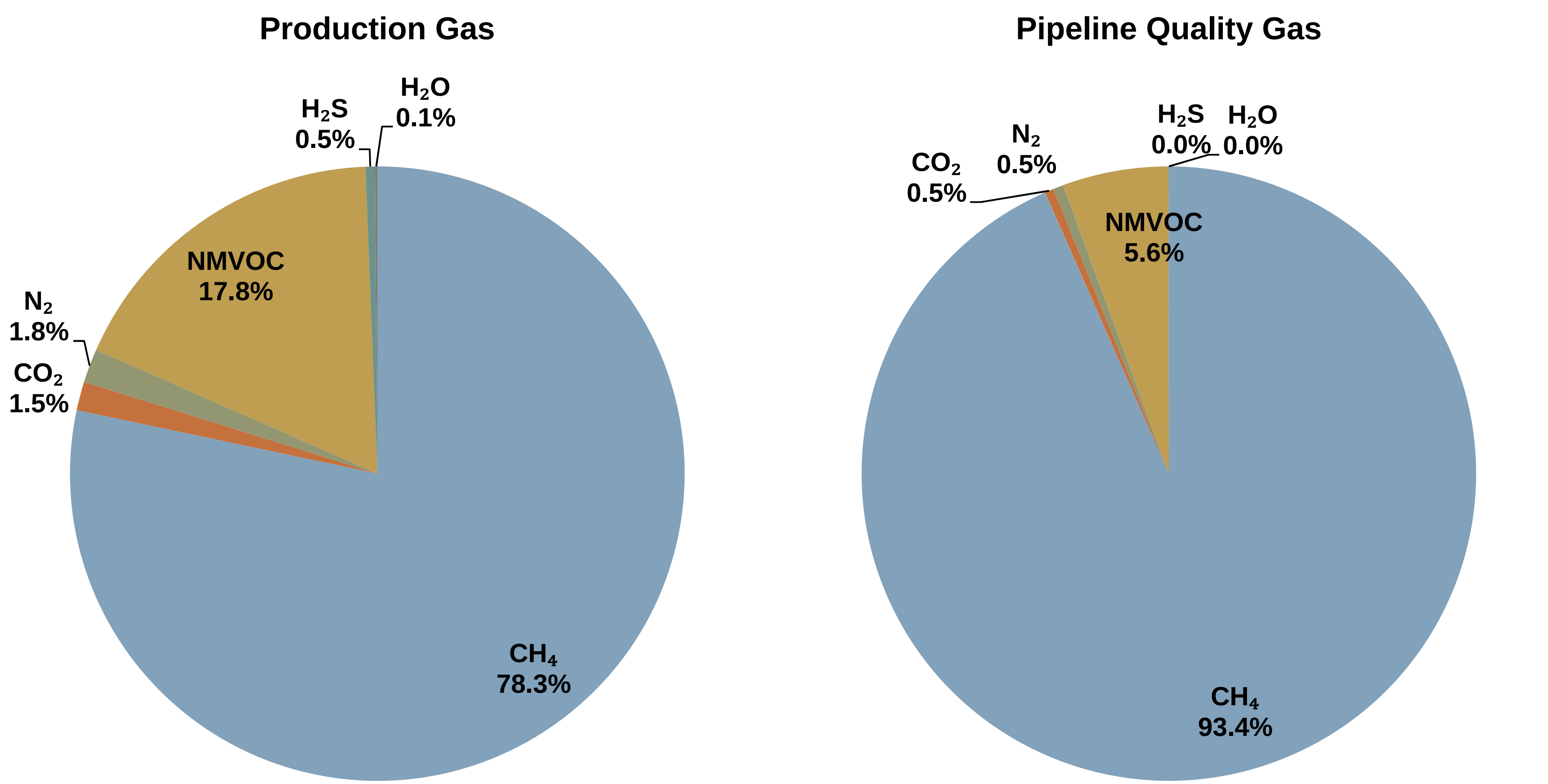
Converted to Global Warming Potential using IPCC 2007 100-year CO_2 equivalents

CO_2 = 1
CH_4 = 25
N_2O = 298
SF_6 = 22,800

NETL Life Cycle Model for Natural Gas



Natural Gas Composition by Mass



Carbon content (75%) and energy content (1,027 btu/cf) of pipeline quality gas is very similar to raw production gas (within 99% of both values)

Natural Gas Extraction Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
Estimated Ultimate Recovery (EUR), Production Gas	BCF/well	8.6	4.4	67.7	1.2	3.0	0.2
Production Rate (30-yr average)	MCF/day	782	399	6,179	110	274	20
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	MCF/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	MCF/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	MCF/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.043	0.043	0.010	0.043	0.043	0.043

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Acid Gas Removal (AGR) and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%					
Methane Absorbed into Amine Solution	lb CH_4/MCF	0.04					
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/MCF	0.56					
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/MCF	0.21					
NMVOC Absorbed into Amine Solution	lb NMVOC/MCF	6.59					
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%					
Water Removed by Dehydrator Unit	lb H_2O/MCF	0.045					
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/MCF	0.0003					
Pneumatic Devices & Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%					
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05					
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.02					
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.03					

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Natural Gas Transmission Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Emissions on Transmission Infrastructure							
Pipeline Transport Distance (national average)	Miles	450					
Transmission Pipeline Infrastructure, Fugitive	lb CH_4/MCF-Mile	0.0003					
Transmission Pipeline Infrastructure, Fugitive (per 450 miles)	lb CH_4/MCF	0.15					
Natural Gas Compression on Transmission Infrastructure							
Distance Between Compressor Stations	Miles	75					
Compression, Gas-powered Reciprocating	Percent	29%					
Compression, Gas-powered Centrifugal	Percent	64%					
Compression, Electrical Centrifugal	Percent	7%					

Uncertainty Analysis Modeling Parameters

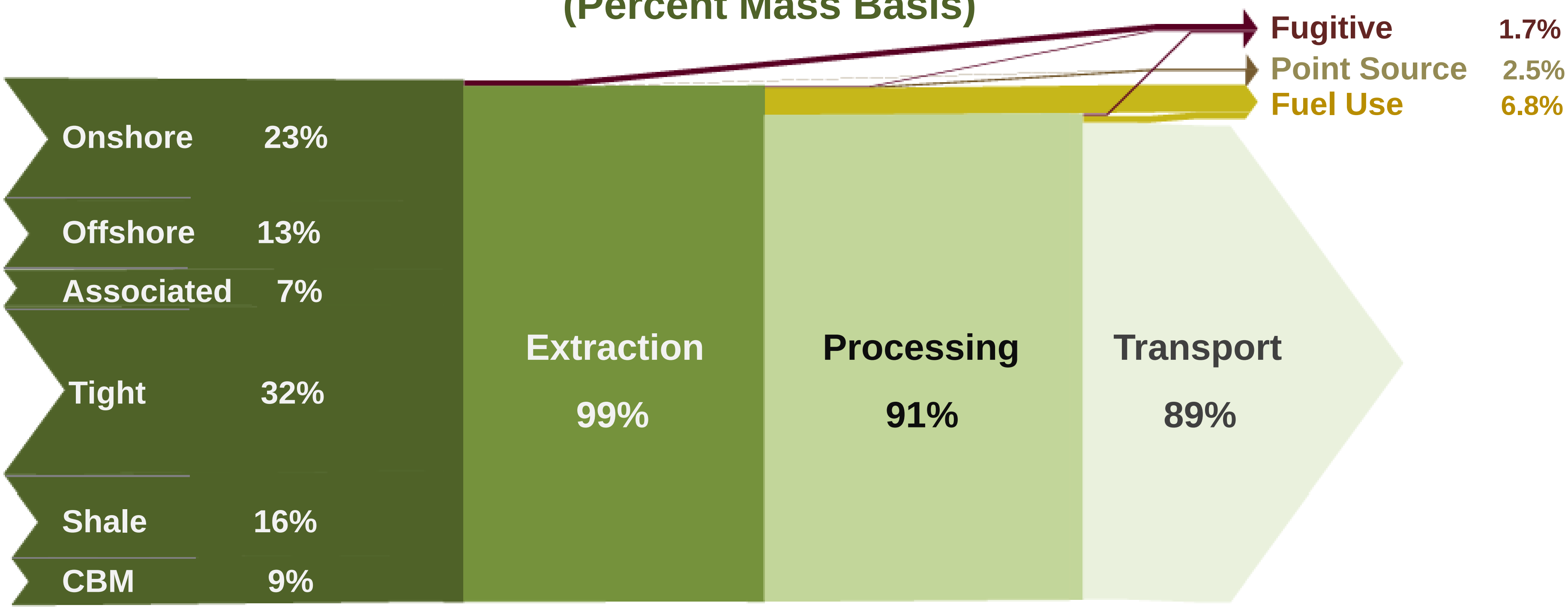
Parameter	Units	Scenario	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Production Rate	MCF/day	Low	403 (-49%)	254 (-36%)	3,140 (-49%)	77 (-30%)	192 (-30%)	14 (-30%)
		Nominal	**782**	**399**	**6,179**	**110**	**274**	**20**
		High	1,545 (+97%)	783 (+96%)	12,284 (+99%)	142 (+30%)	356 (+30%)	26 (+30%)
Flaring Rate at Well	%	Low	41% (-20%)	41% (-20%)	41% (-20%)	12% (-20%)	12% (-20%)	41% (-20%)
		Nominal	**51%**	**51%**	**51%**	**15%**	**15%**	**51%**
		High	61% (+20%)	61% (+20%)	61% (+20%)	18% (+20%)	18% (+20%)	61% (+20%)
Pipeline Distance	miles	Low	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)
		Nominal	**450**	**450**	**450**	**450**	**450**	**450**
		High	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)

Error bars reported are based on setting each of the three parameters above to the values that generate the lowest and highest result.

Note: “Production Rate” and “Flaring Rate at Well” have an inverse relationship on the effect of the study result. For example to generate the lower bound on the uncertainty range both “Production Rate” and “Flaring Rate Well” were set to “High” and “Pipeline Distance” was set to “Low”.

Accounting for Natural Gas from Extraction thru Delivery to a Large End-User

(Percent Mass Basis)

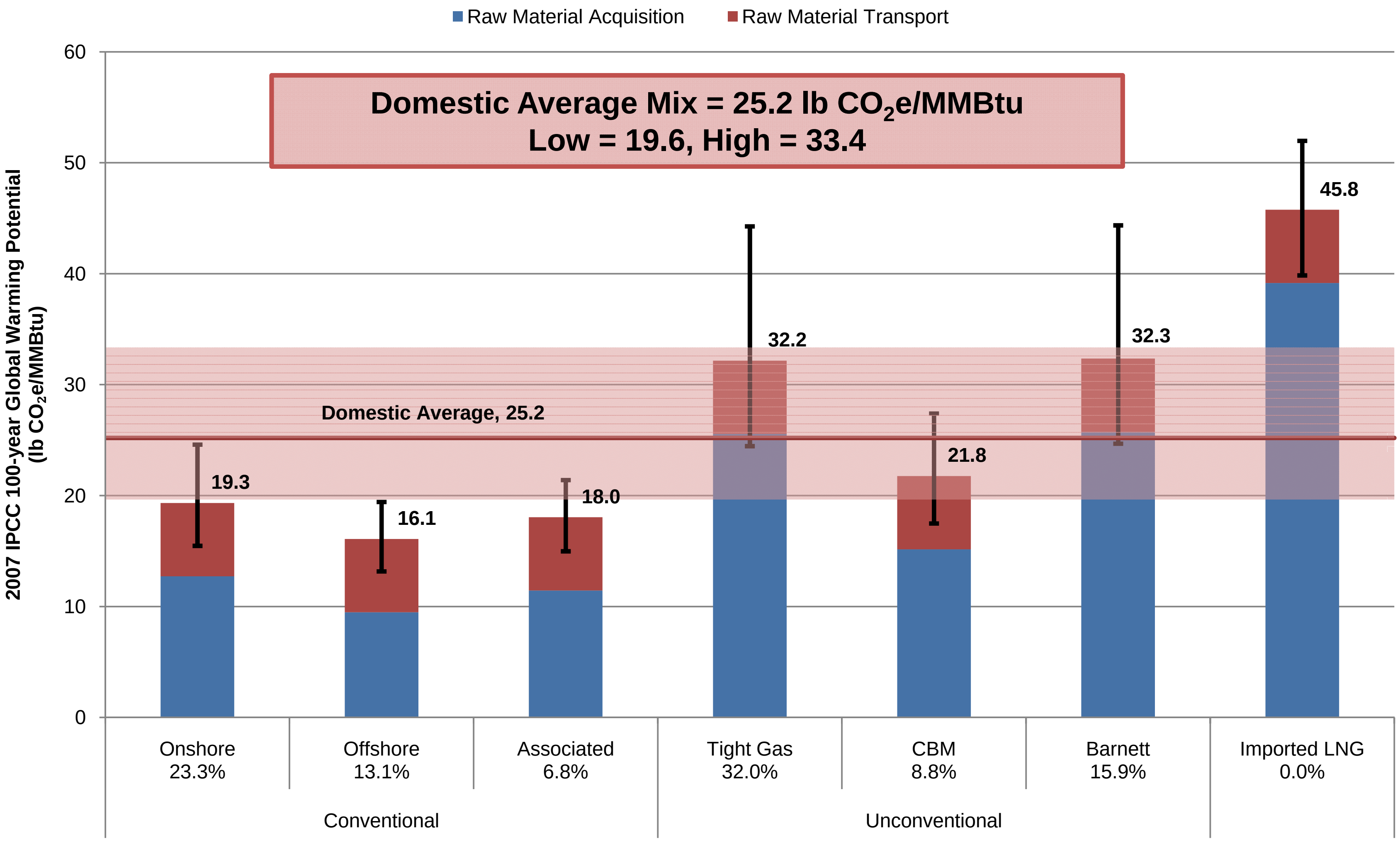


Natural Gas Resource Table	Raw Material Acquisition		Raw Material Transport	Cradle-to-Gate Total:
	Extraction	Processing		
Extracted from Ground	100%	N/A	N/A	100%
Fugitive Losses	1.1%	0.2%	0.4%	1.7%
Point Source Losses (Vented or Flared)	0.1%	2.4%	0.0%	2.5%
Fuel Use	0.0%	5.3%	1.6%	6.8%
Delivered to End User	N/A	N/A	89.0%	89.0%

11% of Natural Gas Extracted from the Earth is Consumed for Fuel Use, Flared, or Emitted to the Atmosphere (point source or fugitive)

Of this, 62% is Used to Power Equipment

Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

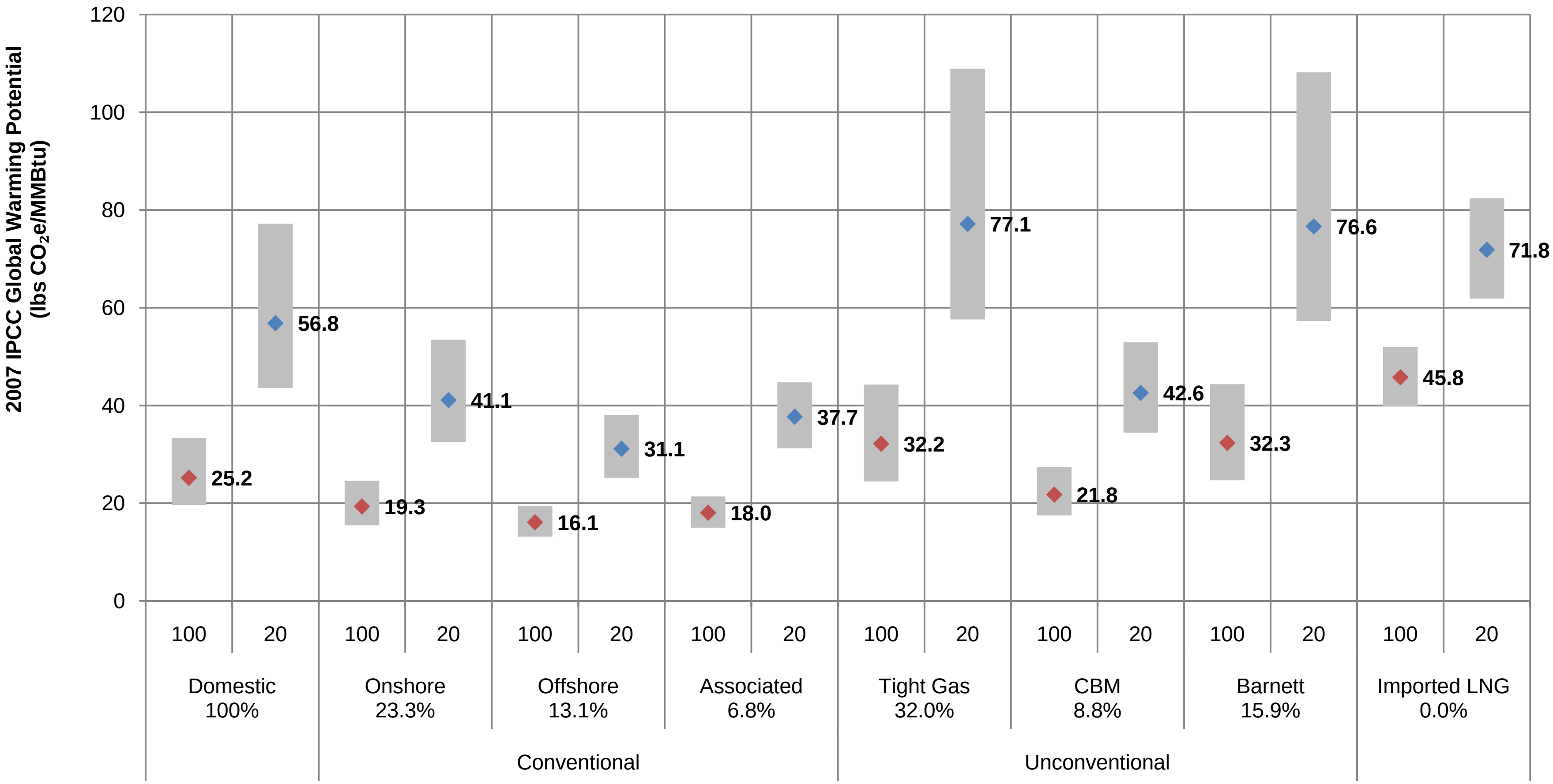


Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

Comparison of 2007 IPCC GWP Time Horizons:

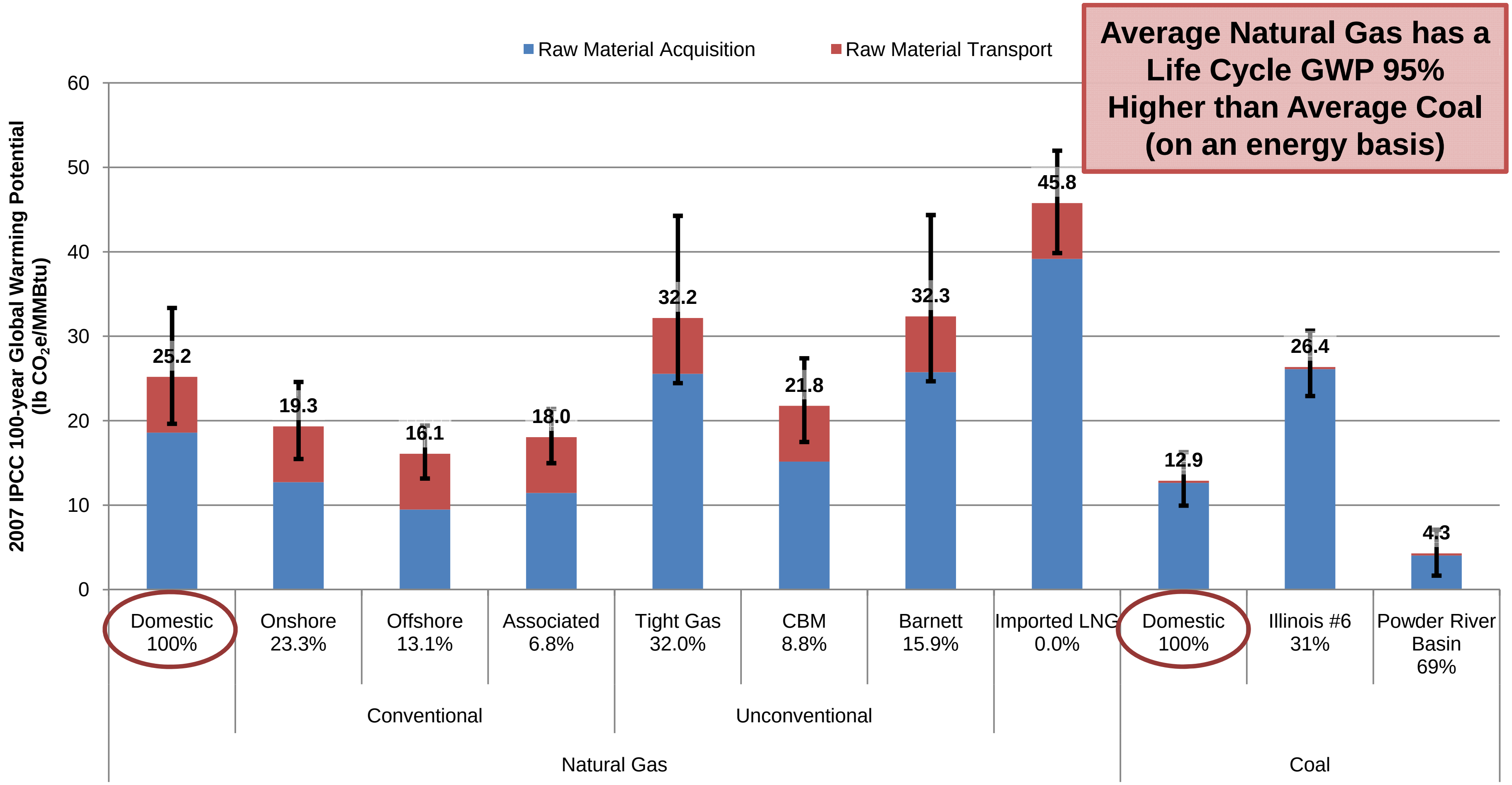
100-year Time Horizon: CO_2 = 1, CH_4 = 25, N_2O = 298

20-year Time Horizon: CO_2 = 1, CH_4 = 72, N_2O = 289

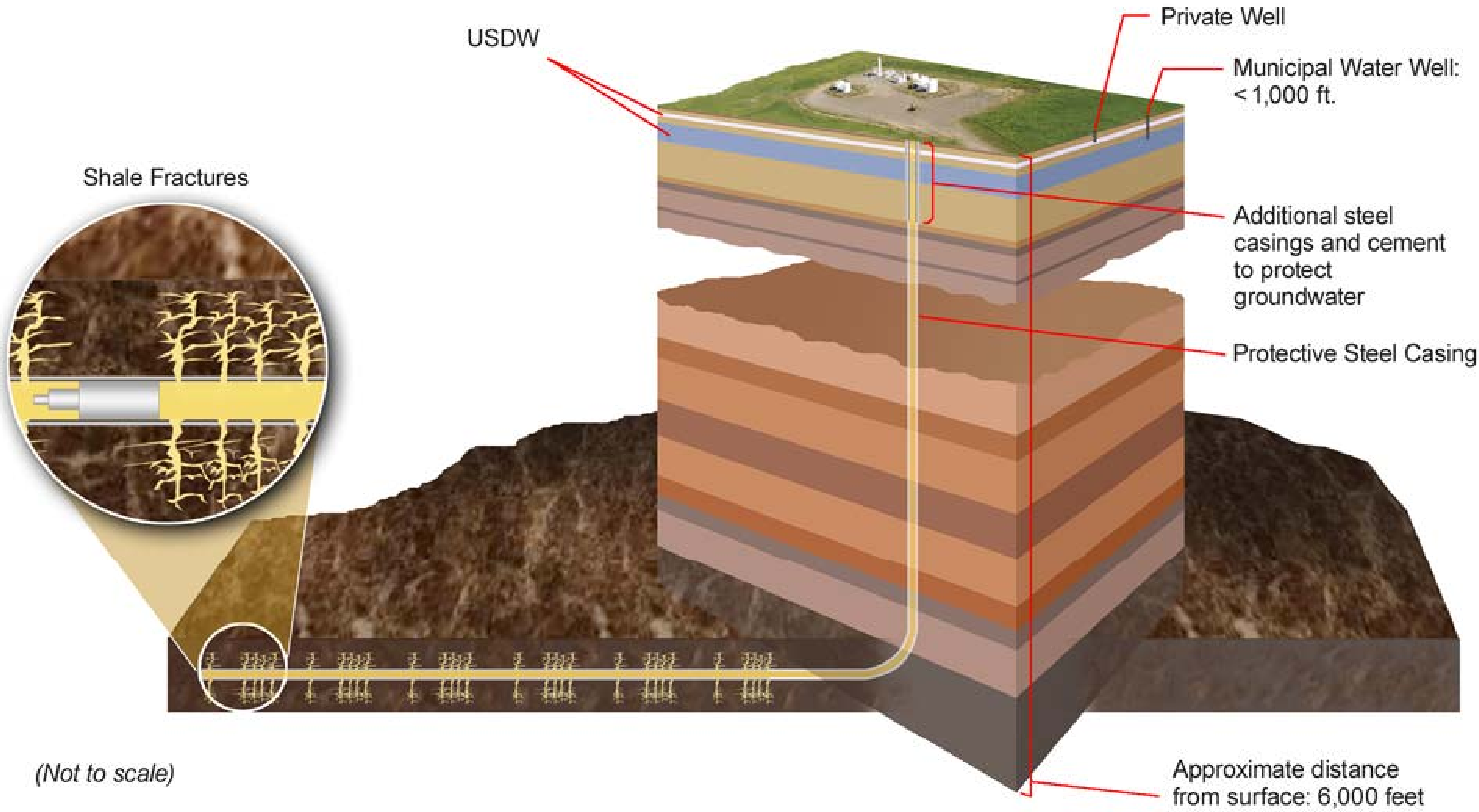


Life Cycle GHG Results for "Average" Natural Gas Extraction and Delivery to a Large End-User

Comparison of Natural Gas and Coal Energy Feedstock GHG Profiles



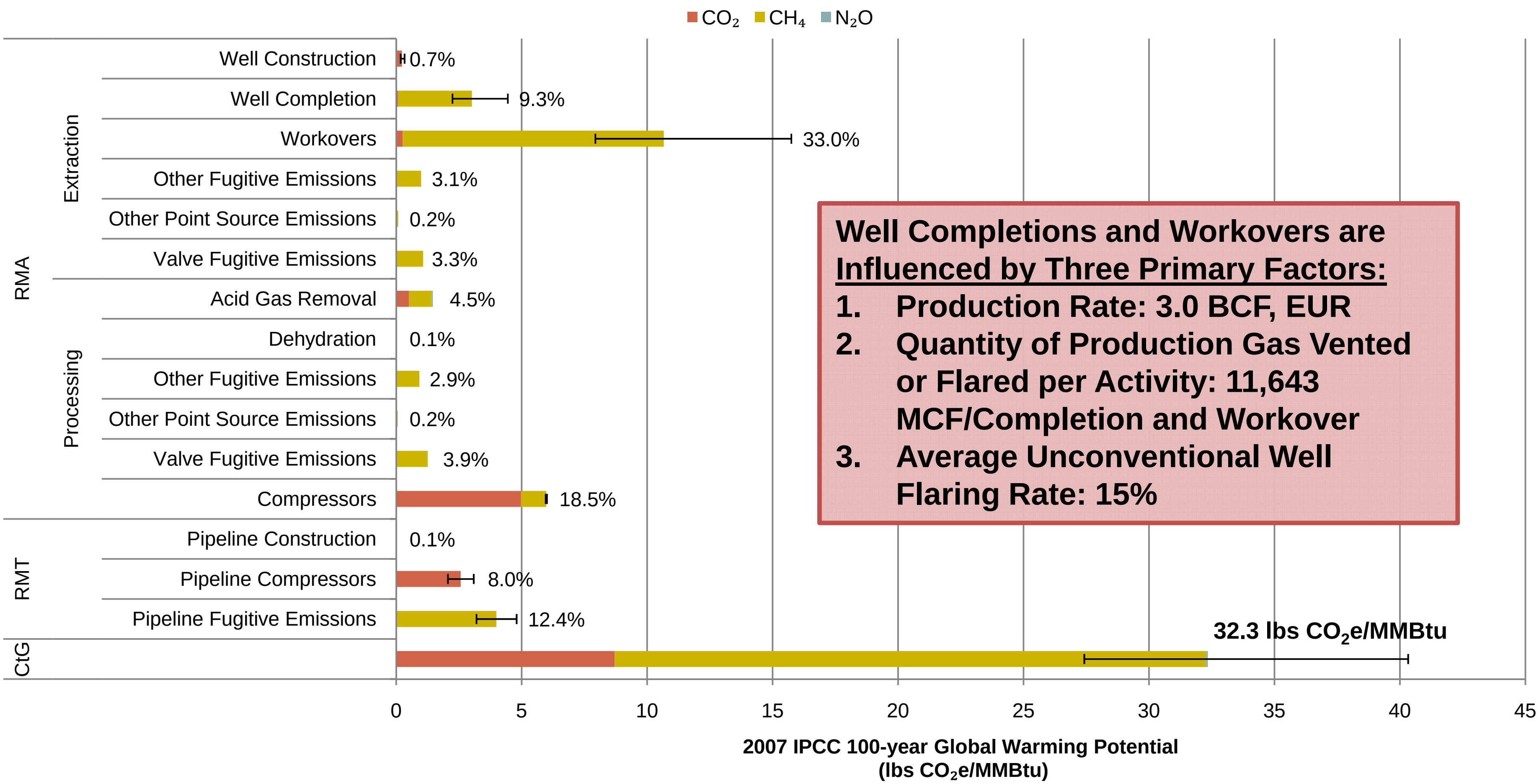
A Deeper Look at Unconventional Natural Gas Extraction via Horizontal Well, Hydraulic Fracturing (*the Barnett Shale Model*)



Source: NETL, *Shale Gas: Applying Technology to Solve America's Energy Challenge*, January 2011

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

GWP Result: IPCC 2007, 100-yr (lb CO_2e/MMBtu)

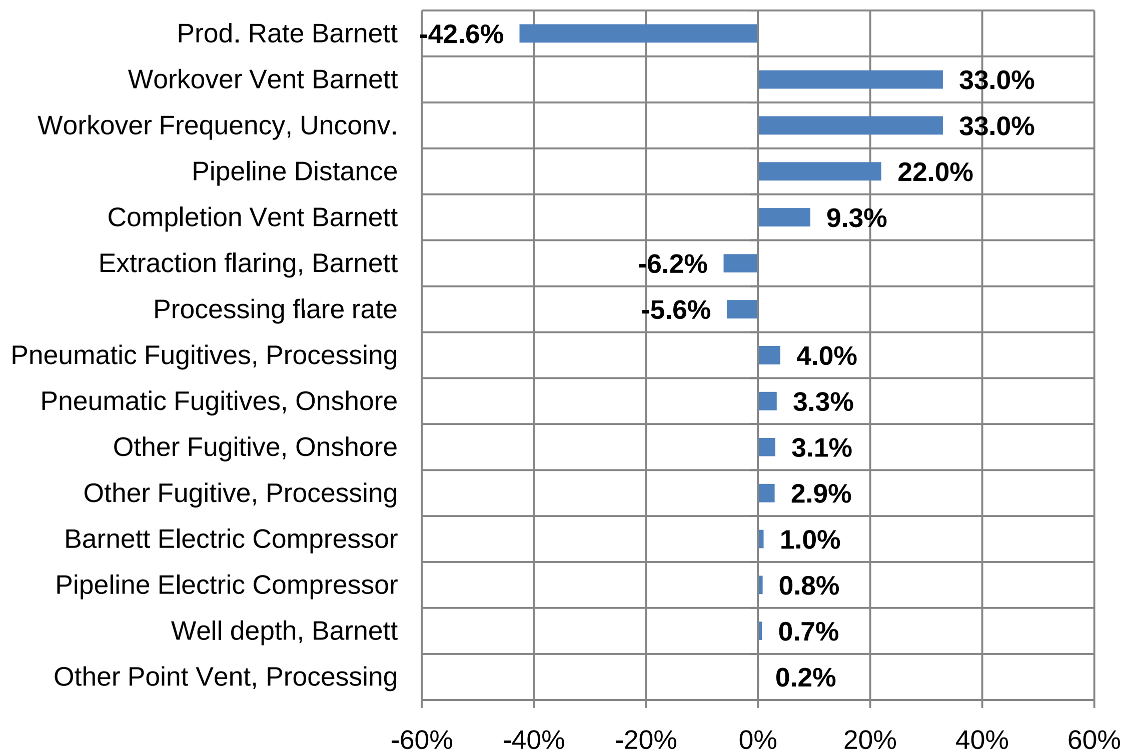


Well Completions and Workovers are <u>Influenced by Three Primary Factors:</u>

1. **Production Rate: 3.0 BCF, EUR**
2. **Quantity of Production Gas Vented or Flared per Activity: 11,643 MCF/Completion and Workover**
3. **Average Unconventional Well Flaring Rate: 15%**

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

Sensitivity Analysis



Default Value	Units
11,508	lb/day
489,023	lb/episode
0.118	episodes/yr
450	miles
489,023	lb/episode
15.0	%
100	%
0.001480	lb fugitives/lb processed gas
0.001210	lb fugitives/lb extracted gas
0.001119	lb fugitives/lb extracted gas
0.001089	lb fugitives/lb processed gas
25	%
7	%
13,000	feet
0.0003940	lb fugitives/lb processed gas

“0%” = 32.3 lb CO_2e/MMBtu Delivered; IPCC 2007, 100-yr Time Horizon

Example: A 1% increase in production rate from 11,508 lb/day to 11,623 lb/day results in a 0.426% decrease in cradle-to-gate GWP, from 32.3 to 32.2 lbs CO_2e/MMBtu

Question #6:

How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?

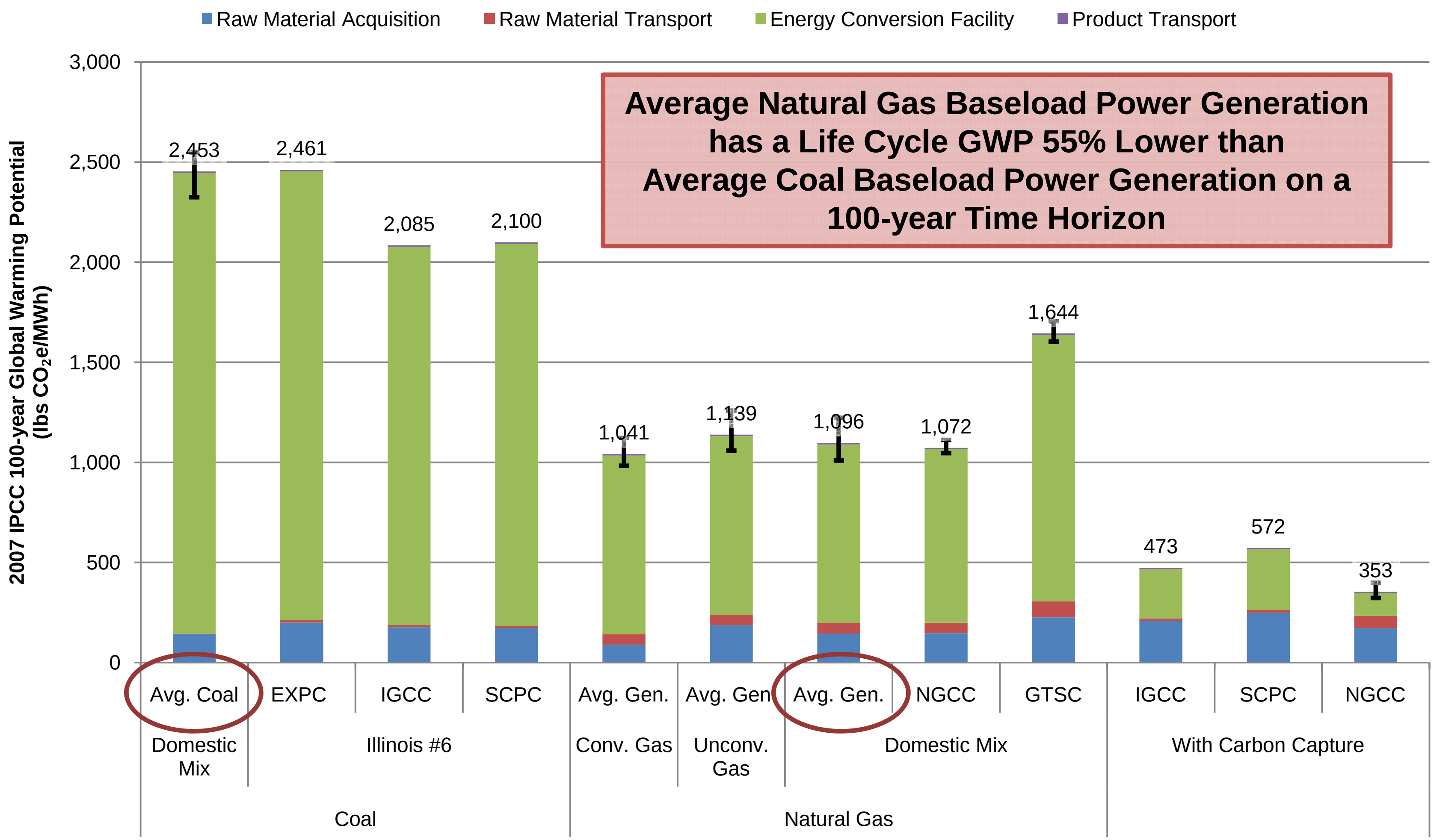
Power Technology Modeling Properties

Plant Type	Plant Type Abbreviation	Fuel Type	Capacity (MW)	Capacity Factor	Net Plant HHV Efficiency
2009 Average Coal Fired Power Plant[a]	Avg. Coal	Domestic Average	Not Calculated	Not Calculated	33.0%
Existing Pulverized Coal Plant	EXPC	Illinois No. 6	434	85%	35.0%
Integrated Gasification Combined Cycle Plant	IGCC	Illinois No. 6	622	80%	39.0%
Super Critical Pulverized Coal Plant	SCPC	Illinois No. 6	550	85%	36.8%
2009 Average Baseload (> 40 MW) Natural Gas Plant[a]	Avg. Gen.	Domestic Average	Not Calculated	Not Calculated	47.1%
Natural Gas Combined Cycle Plant	NGCC	Domestic Average	555	85%	50.2%
Gas Turbine Simple Cycle	GTSC	Domestic Average	360	85%	32.6%
Integrated Gasification Combined Cycle Plant with 90% Carbon Capture	IGCC/CCS	Illinois No. 6	543	80%	32.6%
Super Critical Pulverized Coal Plant with 90% Carbon Capture	SCPC/CCS	Illinois No. 6	550	85%	26.2%
Natural Gas Combined Cycle Plant with 90% Carbon Capture	NGCC/CCS	Domestic Average	474	85%	42.8%

[a] **Net plant higher heating value (HHV) efficiency reported is based on the weighted mean of the 2007 fleet as reported by U.S. EPA, eGrid (2010).**

Comparison of Power Generation Technology Life Cycle GHG Footprints

Raw Material Acquisition thru Delivery to End Customer (lb CO_2e/MWh)



Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

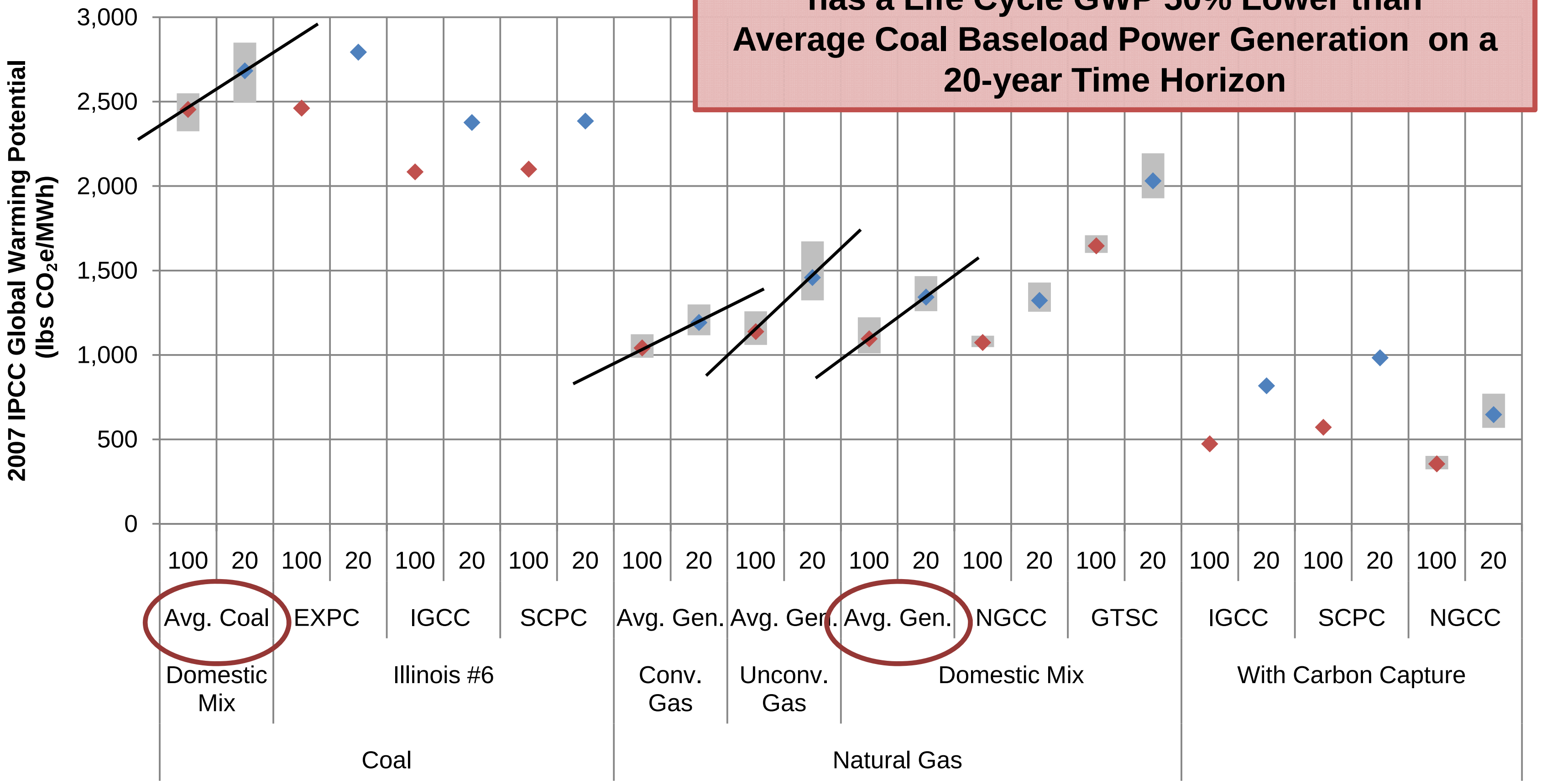
Comparison of Power Generation Technology Life Cycle GHG Footprints (lbs CO_2e/MWh)

Comparison of 2007 IPCC GWP Time Horizons:

100-year Time Horizon: $CO_2 = 1$, $CH_4 = 25$, $N_2O = 298$

20-year Time Horizon: $CO_2 = 1$, $CH_4 = 72$, $N_2O = 289$

Average Natural Gas Baseload Power Generation has a Life Cycle GWP 50% Lower than Average Coal Baseload Power Generation on a 20-year Time Horizon



Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Study Data Limitations

- **Data Uncertainty**
  - Episodic emission factors
  - Formation-specific production rates
  - Flaring rates (extraction and processing)
  - Natural gas pipeline transport distance

- **Data Availability**
  - Formation-specific gas compositions (including CH_4, H_2S, NMVOC, and water)
  - Effectiveness of green completions and workovers
  - Fugitive emissions from around wellheads (between the well casing and the ground)
  - GHG emissions from the production of fracing fluid
  - Direct and indirect GHG emissions from land use from access roads and well pads
  - Gas exploration
  - Treatment of fracing fluid
  - Split between venting and fugitive emissions from pipeline transport

<u>Question #7:</u>

What are the opportunities for reducing GHG emissions?

Technology Opportunities

- **Opportunities for Reducing the GHG Footprint of Natural Gas Extraction and Delivery**
  - Reduce emissions from unconventional gas well completions and workovers
    - Better data is needed to properly characterize this opportunity based on basin type, drilling method, and production rate
  - Improve compressor fuel efficiency
  - Reduce pipeline fugitive emissions thru technology and best management practices (collaborative initiatives)

- **Opportunities for Reducing the GHG Footprint of Natural Gas and Coal-fired Power Generation**
  - Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir (CO_2-EOR)
  - Improve existing power plant efficiency
  - Invest in advanced power research, development, and demonstration

All Opportunities Need to Be Evaluated on a Sustainable Energy Basis: Environmental Performance, Economic Performance, and Social Performance (e.g., energy reliability and security)

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Recent NETL Life Cycle Assessment Reports

Available at http://www.netl.doe.gov/energy-analyses/:

- Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant
- Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant
- Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant
- Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant
- Life Cycle Analysis: Power Studies Compilation Report

Analysis complete, report in draft form:

- Life Cycle GHG Analysis of Natural Gas Extraction and Delivery
- Life Cycle Assessment of Wind Power with GTSC Backup
- Life Cycle Assessment of Nuclear Power

Other related Life Cycle Analysis publications available on NETL web-site:

- Life Cycle Analysis: Power Studies Compilation Report (Pres., LCA X Conference)
- An Assessment of Gate-to-Gate Environmental Life Cycle Performance of Water-Alternating-Gas CO_2-Enhanced Oil Recovery in the Permian Basin (Report)
- A Comparative Assessment of CO_2 Sequestration through Enhanced Oil Recovery and Saline Aquifer Sequestration (Presentation, LCA X Conference)

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production

October 24, 2011

DOE/NETL-2011/1522

U.S. DEPARTMENT OF ENERGY

Disclaimer

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Final Report

October 24, 2011

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Acronyms and Abbreviations

AGR	Acid gas removal
API	American Petroleum Institute
bbl	Barrel
Bcf	Billion cubic feet
BOE	Barrel of oil equivalent
Btu	British thermal unit
CBM	Coal bed methane
CCS	Carbon capture and sequestration
cf	Cubic feet
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DOE	Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EUR	Estimated ultimate recovery
EXPC	Existing pulverized coal
g	Gram
gal	Gallon
Gg	Gigagram
GHG	Greenhouse gas
GTSC	Gas turbine simple cycle
GWP	Global warming potential
H_2S	Hydrogen sulfide
hp-hr	Horsepower-hour
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
km	Kilometer
kWh	Kilowatt-hour
lb, lbs	Pound, pounds
LCA	Life cycle assessment, analysis
LNG	Liquefied natural gas
m	Meter
m^3	Meters cubed
Mbbl	Thousand barrels
Mcf	Thousand cubic feet
MJ	Megajoule
MMbbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NMVOC	Non-methane volatile organic compound
NREL	National Renewable Energy Laboratory
PRB	Powder River Basin
psig	Pounds per square inch gauge
PT	Product transport
RMA	Raw material acquisition
RMT	Raw material transport
SCPC	Super critical pulverized coal
T&D	Transmission and distribution
Tcf	Trillion cubic feet
ton	Short ton (2,000 lb)
tonne	Metric ton (1,000 kg)
UP	Unit process

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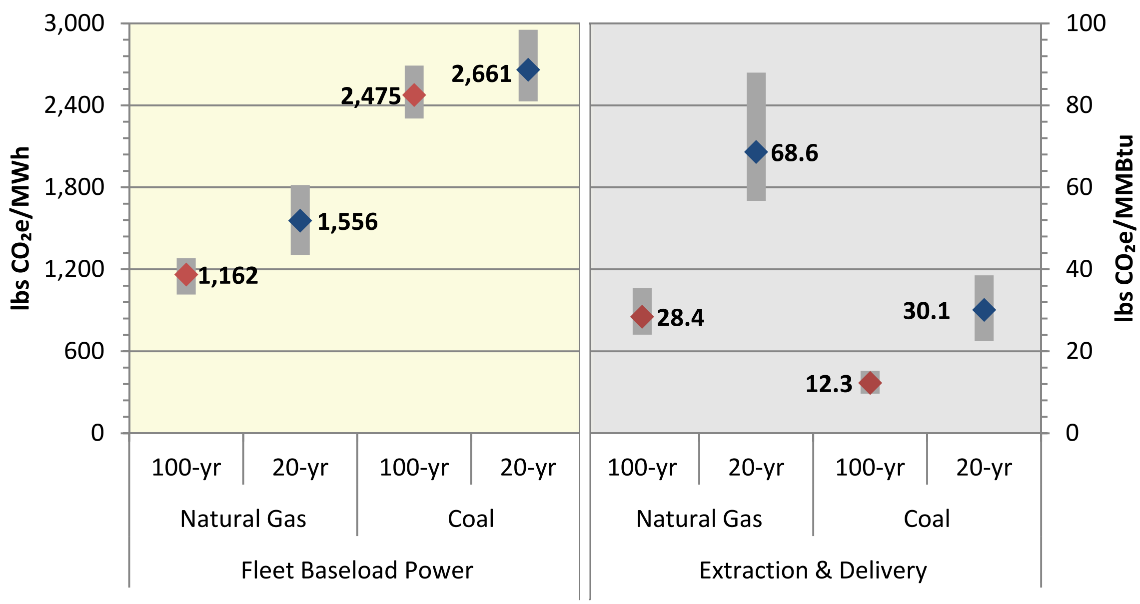
Executive Summary

Natural gas-fired baseload power production has life cycle greenhouse gas emissions 42 to 53 percent lower than those for coal-fired baseload electricity, after accounting for a wide range of variability and compared across different assumptions of climate impact timing. The lower emissions for natural gas are primarily due to differences in the current fleets' average efficiency – 53 percent for natural gas versus 35 percent for coal, and a higher carbon content per unit of energy for coal than natural gas. Even using unconventional natural gas, from tight sands, shale and coal beds, and compared with a 20-year global warming potential (GWP), natural gas-fired electricity has 39 percent lower greenhouse gas emissions than coal per delivered megawatt-hour (MWh) using current technology.

In a life cycle analysis (LCA), comparisons must be based on providing an equivalent service or function, which in this study is the delivery of 1 MWh of electricity to an end user. This life cycle greenhouse gas inventory also developed upstream (from extraction to delivery to a power plant) emissions for delivered energy feedstocks, including six different domestic sources of natural gas, of which three are unconventional gas, and two types of coal, and then combines them both into domestic mixes. These are important characterizations for the LCA community, and can be used as inputs into a variety of processes. However, these upstream, or cradle-to-gate, results are not appropriate to compare when making energy policy decisions, since the two uncombusted fuels do not provide an equivalent function. These results highlight the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

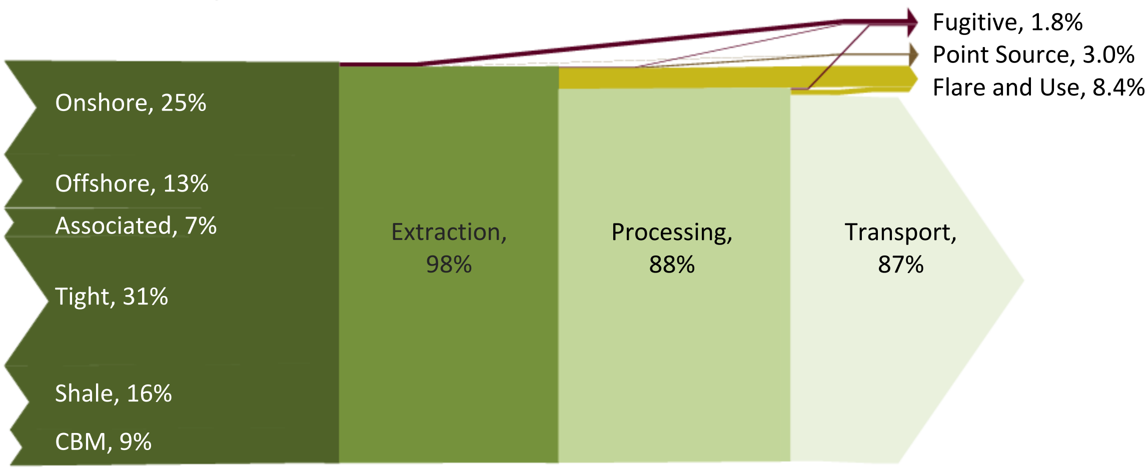
Figure ES-1: Natural Gas and Coal GHG Emissions Comparison



Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases (EPA, 2011b). As **Figure ES-2** shows, there are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —64 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy. Note that this figure accounts for the total mass of natural gas extracted from the earth, including water, acid gases, and other non-methane content.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 24 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

Figure ES-2: Cradle-to-Gate Reduction in Delivered Natural Gas for 2009



The conclusions drawn from this analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few key parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

Table ES-1: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

This analysis inventoried both average and marginal production rates for each natural gas type, with results shown in **Table ES-1**. The average represents natural gas produced from all wells, including older and low productivity stripper wells. The marginal production rate represents natural gas from newer, higher productivity wells. The largest difference was for onshore conventional natural gas, which had a 41 percent reduction in upstream greenhouse gas emissions from 20.1 to 34.2 lbs CO_2e/MMBtu when going from marginal to average production rates. This change has little impact on emissions from power production.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all options need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security. There are many opportunities for decreasing the greenhouse gas emissions from natural gas and coal extraction, delivery and power production, including reducing fugitive methane emissions at wells and mines, and implementing advanced combustion technologies and carbon capture and storage.

1 Introduction

Natural gas is seen as a cleaner burning and flexible alternative to other fossil fuels, and is used in residential, commercial, industrial, and transportation applications in addition to an expanding role in power production. However, the primary component of natural gas by mass is methane, which is also a powerful greenhouse gas—8 to 72 times as potent as carbon dioxide (Forster et al., 2007). Losses of this methane to the atmosphere during the extraction, transmission, and delivery of natural gas to end users made up 32 percent of U.S. 2009 total methane emissions, and 3 percent of all greenhouse gases (EPA, 2011b). The rate of loss, and the associated emissions, varies with the source of natural gas—both the geographic location of the formation, as well as the technology used to extract the gas.

This report expands upon previous life cycle assessments (LCA) performed by the National Energy Technology Laboratory (NETL) of natural gas power generation technologies by describing in detail the greenhouse gas emissions due to extracting, processing and transporting various sources of natural gas to large end users, and the combustion of that natural gas to produce electricity. Emissions inventories are created for the 2009 average natural gas production, but also for natural gas produced from the next highly-productive well for each source of natural gas. This context allows analysis of what the emissions are, and also what they could be in the future.

This analysis also includes an expanded system which compares the life cycle greenhouse gases (GHGs) from baseload natural gas-fired power plants with the GHGs generated by coal-fired plants, including extraction and transportation of the respective fuels. This comparison provides perspective on the scale of fuel extraction and delivery emissions relative to subsequent emissions from power generation and electricity transmission.

Beyond presenting the inventory, the goal of this report is to provide a clear presentation of NETL's natural gas model, including documentation of key assumptions, data sources, and model sensitivities. Further, areas of large uncertainty in the inventory are highlighted, along with areas for potential improvement for both data collection and greenhouse gas reductions.

This greenhouse gas inventory and analysis are part of a larger comprehensive life cycle assessment being performed on the same natural gas system. That assessment effort includes new sources of shale gas and expands the inventory beyond greenhouse gases to include criteria and hazardous air pollutants, water use and quality, direct and indirect land use and greenhouse gases from land use change.

2 Inventory Method, Assumptions, and Data

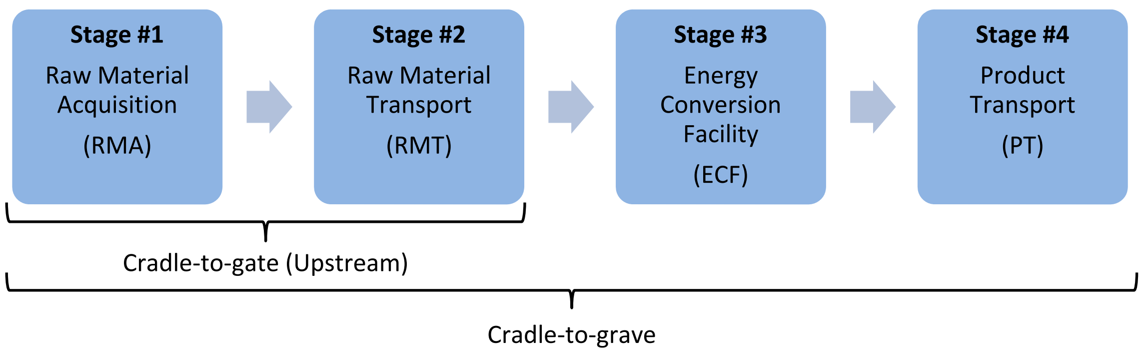
This ISO 14040-compliant inventory and analysis applies the LCA framework to determine the greenhouse gas burdens of natural gas extraction, transport and use in the U.S. The boundaries, basis of comparison, model structure, and data used by this analysis are discussed below. Further detail is available in the Appendix to this document.

2.1 Boundaries

The first piece of this analysis is a cradle-to-gate greenhouse gas inventory that focuses on raw material acquisition and transport; as such, it is also referred to as an upstream inventory, upstream being a relative term (relative, in this case, to the power plant). As shown in **Figure 2-1**, and in more detail in **Figure 2-2**, the boundary of Stage #1 includes all construction and operation activities necessary to extract fuel from the earth, and ends when fuel is extracted, prepared, and ready for final transport to the power plant. Stage #2 includes all construction and operation activities necessary to move fuel from the extraction and processing point to the power plant, and ends at the power plant gate. The boundary of the upstream inventory of natural gas does not include the distribution system of natural gas to small end users, but rather is representative of delivery to a large end user such as a power plant or even a city gate.

The second piece of this analysis is a cradle-to-grave context to compare the greenhouse gas emissions of natural gas extraction and transport with those of electricity production and transmission. Neither piece of analysis includes the use of the produced product, but rather ends when the product is delivered. Coal-fired power systems are used as a further point of comparison.

Figure 2-1: Life Cycle Stages and Boundary Definitions



2.2 Basis of Comparison (Functional Unit)

To establish a basis for comparison, the LCA method requires specification of a functional unit, the goal of which is to define an equivalent service provided by the systems of interest. Within the cradle-to-gate boundary of this analysis, the functional unit is 1 MMBtu of fuel delivered to the gate of an energy conversion facility or other large end user. When the boundaries of the analysis are expanded to include power production, the functional unit is the delivery of 1 MWh of electricity to the consumer. In both contexts, the period over which the service is provided is 30 years.

2.2.1 Global Warming Potential

Greenhouse gases in this inventory are reported on a common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWP) of each gas from the 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (Forster, et al., 2007). The default GWP used is the 100-year time frame, but in some cases, results for the 20-year time frame are presented as well. Selected results comparing all three time frames are included in the Appendix. **Table 2-1** shows the GWPs used for the greenhouse gases inventoried in this study.

Table 2-1: IPCC Global Warming Potentials (Forster, et al., 2007)

GHG	20-year	100-year (Default)	500-year
CO_2	1	1	1
CH_4	72	25	7.6
N_2O	289	298	153
SF_6	16,300	22,800	32,600

2.3 Representativeness of Inventory Results

This inventory uses data gathered from a variety of sources, each of which represents a particular temporal period, geographic location, and state of technology. Since the results of this study are the combination of each of those sources, this section discusses what the results of this study represent in each of those categories.

2.3.1 Temporal

The natural gas upstream inventory results best represent the year 2009, because of the use of the 2009 EIA natural gas production data to create the mix of natural gas sources in the domestic average result and well production rates for each source of natural gas. The year-over-year change to that mix of natural gas sources is small, and the results could represent a period from 2004 to 2012.

This study does not attempt to forecast technological advances or market shifts that might significantly change production rates or emissions of less mature formations.

The inventory results through the conversion of fuel to electricity represent the year 2010 for NETL system study-based technologies and the year 2007 for the fleet average values for coal and natural gas, since this is the vintage of the latest eGRID data release (EPA, 2010). Again, there would be little year-over-year change to the information, and so this LCA could reasonably represent a longer time period, from 2004 to 2015.

Some information included in this inventory pre-dates the temporal period stated above, but was determined to be the latest or highest quality available data.

The time frame of this study is 30 years, but that does not accurately represent a well drilled 30 years from now and operating 60 years into the future. An assumption is made about resource availability based on current estimated ultimate recovery values, and forecasts from the Energy Information Administration (EIA).

2.3.2 Geographic

The results of this inventory are representative of the lower 48 United States. Natural gas from Alaska is neither explicitly included nor excluded, nor are imports and exports. In some situations, source data may not break out information about geographic location, and so is implicitly included in this inventory. However, the error associated with this type of inclusion—or exclusion—is small.

2.3.3 Technological

The natural gas upstream inventory results include two distinct technological representations. The first is a baseline result which represents average 2009 natural gas production, including production from older, less productive wells. Production data from that year is used to create an average domestic mix of natural gas sources, and the production rate of each source well is generally based on 2009 well count and production data. The second set of results is representative of a new marginal unit of natural gas produced in 2009; these results use a variety of methods to create production rates for wells which would create the next unit of natural gas.

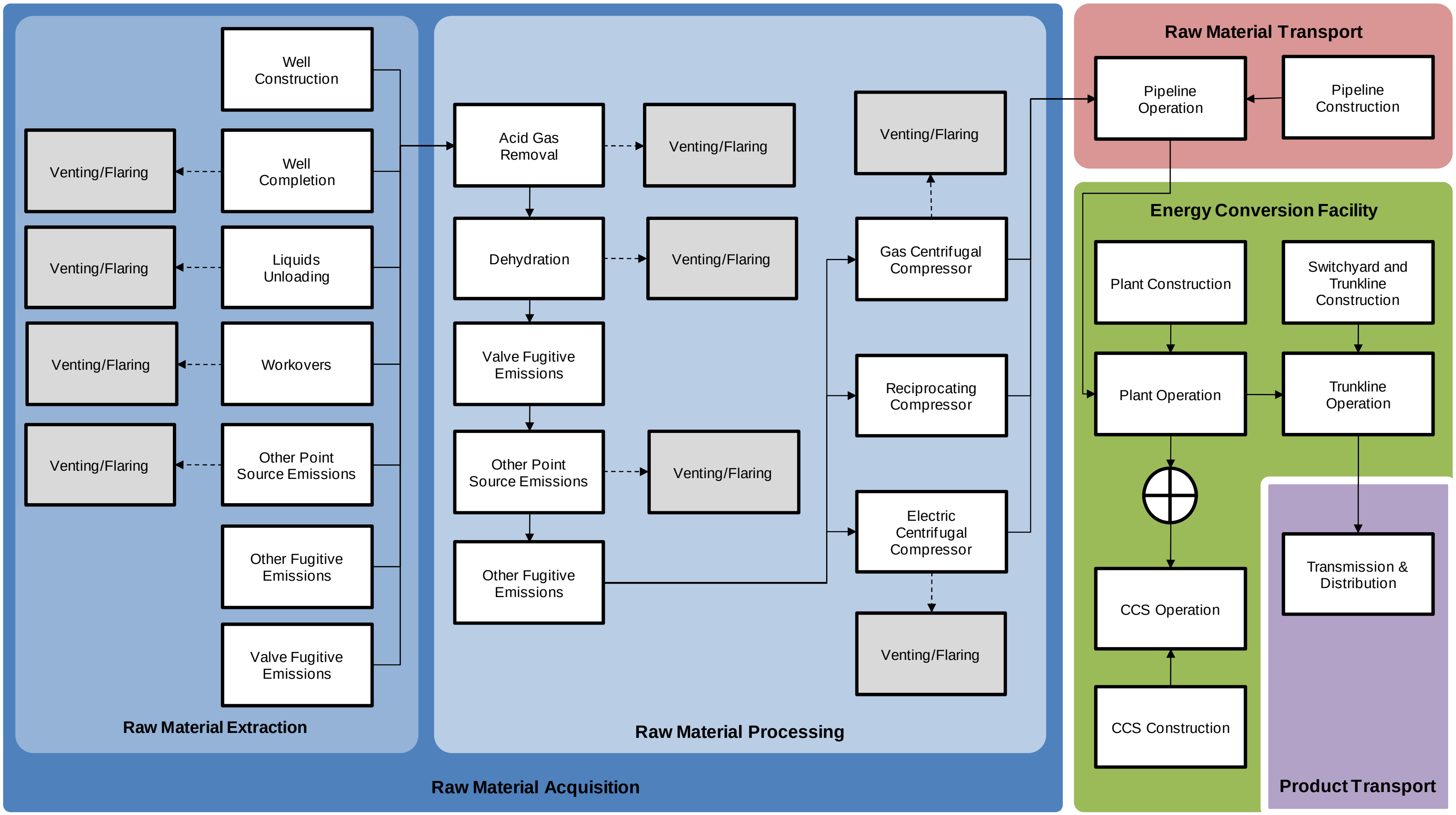
The results of this inventory are representative of currently installed technology as of 2011. This installed base is different from current technology because it includes much older equipment that is still operating.

2.4 Model Structure

All results for this inventory were calculated by NETL's LCA model for natural gas power systems. This model is an interconnected network of operation and construction blocks. Each block in the model, referred to as a unit process, accounts for the key inputs and outputs of an activity. The inputs of a unit process include the purchased fuels, resources from nature (fossil feedstocks, biomass, or water), and man-made raw materials. The outputs of a unit process include air emissions, water effluents, solid waste, and product(s). The role of an LCA model is to converge on the values for all intermediate flows within the interconnected network of unit processes and then scale the flows of all unit processes to a common basis, or functional unit.

The network of unit processes used for the modeling of natural gas power is shown in **Figure 2-2**. Note that only the RMA and RMT portions of the model are necessary to determine the upstream environmental burdens of natural gas; a broader scope—from raw material acquisition through delivery of electricity—is necessary to determine the cradle-to-grave environmental burdens of natural gas power. For simplicity, the following figure shows the extraction and delivery for a generic natural gas scenario; NETL's actual model uses six parallel modules to arrive at the life cycle results for a mix of six types of natural gas. This figure also shows a breakdown of the RMA stage into extraction and processing sub-stages.

Figure 2-2: Natural Gas LCA Modeling Structure



2.5 Data

The primary unit processes of this model are based on data compiled by NETL. Secondary unit processes, such as production of construction materials besides steel, are based on third party data. A full description of data sources is available in the Appendix.

Where data for the inventory is available, high and low values are collected, along with a nominal value. When results are presented, three cases are shown: a nominal case, a high case and a low case. The high and low results (error bars on the results) are a deterministic representation of the variability on the data and not indicative of an underlying distribution or likelihood.

2.5.1 Sources of Natural Gas

This inventory and analysis includes results for natural gas domestically extracted from six sources in the lower 48 states:

1. Conventional onshore
2. Associated
3. Conventional offshore
4. Tight sands
5. Shale formations (Barnett)
6. Coal bed methane

This is not a comprehensive list of natural gas extracted or consumed in the United States. Natural gas extracted in Alaska, 2 percent of domestically extracted natural gas, is included as conventional onshore production. The Haynesville shale play makes up a large portion of unconventional shale production, but it is assumed here that the Barnett play is representative of all shale production. Imported natural gas (18 percent of 2009 total consumption, 88 percent of which is imported via pipeline from Canada) is not included. About 12 percent of imports in 2009 were brought in as liquefied natural gas (LNG) from a variety of countries of origin. While this inventory includes a profile for LNG from offshore extraction in Trinidad and Tobago, this natural gas is not included in the domestic production mix.

Table 2-2 shows the makeup of the domestic production mix in the United States in 2009 and the mix of conventional and unconventional extraction. Note that in 2009 unconventional natural gas sources make up 56 percent of production and the majority of consumption in the Unites States (EIA, 2011a).

Table 2-2: Mix of U.S. Natural Gas Sources (EIA, 2011a)

Source	Conventional			Unconventional		
	Onshore	Associated	Offshore	Tight	Shale	CBM
Domestic Mix	25%	13%	7%	31%	16%	9%
Type Mix	44%			56%		
	56%	15%	29%	56%	28%	15%

The characteristics of these six sources of natural gas are summarized next, including a description of the extraction technologies.

2.5.1.1 Onshore

Conventional onshore natural gas is recovered by vertical drilling techniques. Once a conventional onshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. Compressors are used to move natural gas through all process equipment and pressurize it for pipeline transport. Approximately 25 percent (5.2 TCF) of U.S. natural gas production is from conventional onshore gas wells (EIA, 2011a).

An intermittent procedure called liquids unloading is performed at mature onshore conventional natural gas wells to remove water and other liquids from the wellbore; if these liquids are not removed, the flow of natural gas is impeded. Another intermittent activity is a well workover, which is necessary to repair damage to the wellbore and replace downhole equipment, if necessary.

Natural gas is lost through intentional venting, which may be necessary for safety reasons, during well completion when natural gas recovery equipment or gathering lines have not yet been installed, or when key process equipment is offline for maintenance. When feasible, vented natural gas can be recovered and flared, which reduces the global warming potential of the vented natural gas by converting methane to carbon dioxide. Losses of natural gas also result from fugitive emissions due to the opening and closing of valves, and processes where it is not feasible to use vapor recovery equipment.

2.5.1.2 Offshore

Conventional offshore natural gas is recovered by vertical drilling techniques, similar to onshore. Once a conventional offshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. A natural gas reservoir must be large in order to justify the capital outlay for the completion of the well and construction of an offshore drilling platform, so production rates tend to be very high. Approximately 13 percent (2.7 TCF) of the United States natural gas supply in 2009 was from the conventional extraction from offshore natural gas wells (EIA, 2011a).

2.5.1.3 Associated

Associated natural gas is co-extracted with crude oil. The extraction of onshore associated natural gas is similar to the extraction methods for conventional onshore natural gas (discussed above). Similar to conventional onshore and offshore natural gas wells, associated natural gas extraction includes losses due to well completion, workovers, and fugitive emissions. Since the natural gas is co-produced with petroleum, the use of oil/gas separators is necessary to recover natural gas from the mixed product stream. Another difference between associated natural gas and other conventional natural gas sources is that liquid unloading is not necessary for associated natural gas wells because the flow of petroleum prevents the accumulation of liquids in the well. Approximately 7 percent (1.4 TCF) of U.S. natural gas production is from conventional onshore oil wells (EIA, 2011a). The majority of these wells are in Texas and Louisiana (EIA, 2010).

2.5.1.4 Tight Gas

The largest single source of domestically produced natural gas, and the largest share of unconventional natural gas, is tight gas. From naturalgas.org, tight gas is defined as follows:

> …trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (tight sand). In a conventional natural gas deposit, once drilled, the gas can usually be extracted quite readily, and easily. A great deal more effort has to be put into extracting gas from a tight formation. Several techniques exist that allow natural gas to be extracted, including fracturing and acidizing. However, these techniques are also very costly. Like all unconventional natural gas, the economic incentive must be there to incite

companies to extract this costly gas instead of more easily obtainable, conventional natural gas (NGSA, 2010).

Approximately 31 percent (6.6 TCF) of natural gas produced domestically is from tight deposits. This analysis assumes tight gas wells are vertically drilled and hydraulically fractured.

2.5.1.5 Shale

Natural gas is also dispersed throughout shale formations, such as the Barnett Shale region in northern Texas. Shale gas cannot be recovered using conventional extraction technologies, but is recovered through the use of horizontal drilling and hydraulic fracturing (hydrofracking). Horizontal drilling creates a wellbore that runs the length of a shale formation, and hydrofracking uses high pressure fluid (a mixture of water, surfactants, and proppants) for breaking apart the shale formation and facilitating the flow of natural gas. Hydrofracking is performed during the original completion of a shale gas well, but due to the steeply declining production curves of shale gas wells, hydrofracking is also performed during the workover of shale gas wells. Unlike conventional natural gas wells, shale gas wells do not require liquid unloading because wellbore liquids are reduced during workover operations. Natural gas from shale formations accounts for approximately 16 percent (3.3 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.1.6 Coal Bed Methane

Natural gas can be recovered from coal seams through the use of shallow horizontal drilling. The development of a well for coal bed methane requires horizontal drilling followed by a depressurization period during which naturally-occurring water is discharged from the coal seam. Coal bed methane (CBM) wells do not require liquid unloading and the emissions from CBM workovers are similar to those for shale gas wells. The production of natural gas from CBM wells accounts for approximately 9 percent (1.8 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.2 Natural Gas Composition

Relevant to all phases of the life cycle, the composition of natural gas varies considerably depending on source, and even within a source. For simplicity, a single assumption regarding natural gas composition is used, although that composition is modified as the natural gas is prepared for the pipeline (EPA, 2011a). **Table 2-3** shows the composition on a mass basis of production and pipeline quality natural gas. The pipeline quality natural gas has had water and acid gases (CO_2 and H_2S) removed, and non-methane VOCs either flared or separated for sale. The pipeline quality natural gas has higher methane content per unit mass. The energy content does not change significantly.

Table 2-3: Natural Gas Composition on a Mass Basis

Component	Production	Pipeline Quality
CH_4 (Methane)	78.3%	92.8%
NMVOC (Non-methane VOCs)	17.8%	5.54%
N_2 (Nitrogen)	1.77%	0.55%
CO_2 (Carbon dioxide)	1.51%	0.47%
H_2S (Hydrogen Sulfide)	0.50%	0.01%
H_2O (Water)	0.12%	0.01%

2.5.3 Data for Natural Gas Extraction

This analysis models the extraction of natural gas by characterizing key construction and operation activities at the natural gas wellhead. A summary of each unit process of NETL's model of natural gas extraction is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for these unit processes.

2.5.3.1 Well Construction

Data for the construction and installation of natural gas wellheads are based on the energy requirements and linear drill speed of diesel-powered drilling rigs, the depths of wells, and the casing materials required for a wellbore. Construction and installation are one-time activities that are apportioned to each unit of natural gas operations by dividing all construction and installation emissions by the lifetime in years and production in million cubic feet of a typical well.

2.5.3.2 Well Completion

The data for well completion describe the emission of natural gas that occurs during the development of a well, before natural gas recovery and other equipment have been installed at the wellhead. Well completion is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from an event that occurs one time in the life of a well.

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a).

Within the unconventional well category, NETL adjusted EPA's completion emission factors to account for the different reservoir pressures of unconventional wells. NETL used EPA's emission factor of 9,175 Mcf of methane per completion for Barnett Shale gas wells. NETL adjusted this emission factor downward for tight gas in order to account for the lower reservoir pressures of tight gas wells. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor. The production rate of tight gas wells is 40 percent of that for Barnett Shale wells (with EURs of 1.2 BCF for tight gas vs. 3.0 BCF for Barnett Shale), and thus NETL assumes that the completion emission factor for tight gas wells is 3,670 Mcf of methane per completion (40 percent × 9,175 = 3,670).

CBM wells also involve unconventional extraction technologies, but have lower reservoir pressures than shale gas or tight gas wells. The corresponding emission factor of CBM wells is 49.57 Mcf of methane per completion, which is the well completion factor that EPA reports for low pressure wells (EPA, 2011a).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. For instance, when factoring for the density of natural gas, a conventional completion emission of 36.65 Mcf is equivalent to 1,540 lbs. CH_4/completion.

2.5.3.3 Liquid Unloading

The data for liquids unloading describe the emission of natural gas that occurs when water and other condensates are removed from a well. These liquids impede the flow of natural gas from the well, and thus producers must occasionally remove the liquids from the wellbore. Liquid unloading is necessary for conventional gas wells—it is not necessary for unconventional wells or associated gas wells. Liquid unloading is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well.

The methane emissions from liquids unloading are based on the total unloading emissions from conventional wells in 2007, the number of active conventional wells in 2007, and the average frequency of liquids unloading (EPA, 2011a). The resulting emission factor for liquids unloading is 776 lb CH_4/episode.

2.5.3.4 Workovers

Well workovers are necessary for cleaning wells and, in the case of shale and tight gas wells, use hydraulic fracturing to re-stimulate natural gas formations. The workover of a well is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well. As stated in EPA's technical support document of the petroleum and natural gas industry (EPA, 2011a), conventional wells produce 2.454 Mcf of methane per workover. EPA assumes that the emissions from unconventional well workovers are equal to the emission factors for unconventional well completion (EPA, 2011a). Thus, for unconventional wells, this analysis uses the same emission factors for well completion (discussed above) and well workovers.

Unlike well completions, well workovers occur more than one time during the life of a well. For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

2.5.3.5 Other Point Source Emissions

Routine emissions from natural gas extraction include gas that is released from wellhead and gathering equipment. These emissions are referred to as "other point source emissions." This analysis assumes that a portion of these emissions are flared, while the balance is vented to the atmosphere. For conventional wells, 51 percent of other point source emissions are flared, while for unconventional wells, a 15 percent flaring rate is used (EPA, 2011a).

Data for the other point source emissions from natural gas extraction are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for onshore and offshore wells. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other point source emissions from natural gas extraction are shown in **Table 2-4**.

2.5.3.6 Other Fugitive Emissions

Routine emissions from natural gas extraction include fugitive emissions from equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions," and cannot be captured for flaring. Data for other fugitive emissions from natural gas extraction are based on EPA data for onshore and offshore natural gas wells (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other fugitive emissions from natural gas extraction are included in **Table 2-4**.

2.5.3.7 Valve Fugitive Emissions

The extraction of natural gas uses pneumatic devices for the opening and closing of valves and other control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction site, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from valves (and other pneumatically-operated devices) are based on EPA data for onshore and offshore gas wells (EPA, 2011a). EPA's data are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate. The emission factors for fugitive valve emissions from natural gas extraction are included in **Table 2-4**.

Table 2-4: Other Point Source and Fugitive Emissions from Natural Gas Extraction

NG Extraction Emission Source	Onshore Extraction	Offshore Extraction	Units
Other Point Source Emissions	7.49E-05	3.90E-05	lb CH_4/lb NG extracted
Other Fugitive Emissions	1.02E-03	2.41E-04	lb CH_4/lb NG extracted
Valve Fugitive Emissions (including pneumatic devices)	2.63E-03	1.95E-06	lb CH_4/lb NG extracted

2.5.3.8 Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring at a natural gas well include carbon dioxide, methane, and nitrous oxide. The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.3 percent CH_4, 1.51 percent CO_2, 1.77 percent nitrogen, and 17.8 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). This composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2), the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2, and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4 Data for Natural Gas Processing

This analysis models the processing of natural gas by developing an inventory of key gas processing operations, including acid gas removal, dehydration, and sweetening. Standard engineering calculations were applied to determine the energy and material balances for the operation of key natural gas equipment. A summary of NETL's natural gas processing data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for NETL's natural gas processing data.

2.5.4.1 Acid Gas Removal

Raw natural gas contains hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas. Amine-based processes are the predominant technologies for acid gas removal (AGR). The energy consumed by an amine reboiler accounts for the majority of energy consumed by the AGR process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass of raw natural gas (Foss, 2004) is modeled in this analysis.

In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb of natural gas sweetened (API, 2009).

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and natural gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas.

Non-methane volatile organic compounds (NMVOCs) are a co-product of AGR. A mass balance shows that 84 percent of the vented gas from the AGR process is NMVOC. They are separated and sold as a high value product on the market. Co-product allocation based on the energy content of the natural gas stream exiting the AGR unit and the NMVOC stream was used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

2.5.4.2 Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

NETL’s data for natural gas dehydration accounts for the reboiler used by the dehydration process, the flow rate of glycol solvent, and the methane vented from the regeneration of glycol solvent. All of these activities depend on the concentrations of gas and water that enter and exit the dehydration process. The typical water content for untreated natural gas is 49 lbs. per million cubic feet (MMcf). In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs./MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is three gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gallon (EPA, 2006).

2.5.4.3 Valve Fugitive Emissions

The processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas processing plant, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from pneumatic devices are based on EPA data for gas processing plants (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific processing activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for valve fugitive emissions from natural gas processing is included in **Table 2-5**.

2.5.4.4 Other Point Source Emissions

Routine emissions from natural gas processing include gas that is released from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other point source emissions." This analysis assumes that 100 percent of other point source emissions from natural gas processing are captured and flared.

Data for the other point source emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other point source emissions from natural gas processing is included in **Table 2-5**.

2.5.4.5 Other Fugitive Emissions

Routine emissions from natural gas processing include fugitive emissions from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions." and cannot be captured for flaring.

Data for the other fugitive emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other fugitive emissions from natural gas processing is included in **Table 2-5**.

Table 2-5: Other Point Source and Fugitive Emissions from Natural Gas Processing

NG Processing Emission Source	Value	Units
Other Point Source Emissions	3.68E-04	lb CH_4/lb NG processed
Other Fugitive Emissions	8.25E-04	lb CH_4/lb NG processed
Valve Fugitive Emissions (including pneumatic devices)	6.33E-06	lb CH_4/lb NG processed

2.5.4.6 Venting and Flaring

The venting and flaring process for natural gas processing is similar to that of natural gas extraction, described in **Section 2.5.3.8**, except all of the other point source emissions at the natural gas processing plant are flared. The combustion products of flaring at a natural gas processing plant include carbon dioxide, methane, and nitrous oxide. The mass composition of pipeline quality natural gas is 92.8 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.5 percent NMVOCs; this composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2); the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2; and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4.7 Natural Gas Compression

Compressors are used to increase the natural gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. Three types of compressors are used at natural gas processing plants: gas-powered reciprocating compressors, gas-powered centrifugal compressors, and electrically-powered centrifugal compressors.

Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Burklin & Heaney, 2006).

Gas-powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures).

If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a populated area. An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine.

Centrifugal compressors (both gas-powered and electrically-powered) lose natural gas through a process called wet seal degassing, which involves the regeneration of lubricating oil that is circulated between the compressor shaft and housing. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010) and implies a wet seal degassing emission factor of 0.0069 lb of natural gas/lb of processed natural gas.

2.5.5 Data for Natural Gas Transport

This analysis models the transport of natural gas by characterizing key construction and operation activities for pipeline transport. A summary of NETL's natural gas transport data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculation methods for NETL's natural gas transport data.

2.5.5.1 Natural Gas Transport Construction

The construction of a natural gas pipeline is based on the linear density, material requirements, and length for pipeline construction. A typical natural gas transmission pipeline is 32 inches in diameter and is constructed of carbon steel. Construction is a one-time activity that is apportioned to each unit of natural gas transport by dividing all construction burdens by the book life in years and throughput in million cubic feet of the pipeline.

2.5.5.2 Natural Gas Transport Operations

Data for the operation of a natural gas pipeline are based on national inventory data for methane emissions from natural gas transmission (EPA, 2011b) and a national pipeline compressor survey compiled by EIA (Gaul, 2011). Air emissions from pipeline operations are calculated by applying AP-42 emission factors to the portion of pipeline natural gas that is combusted for compressor power. Seven percent of U.S. natural gas pipeline compressors rely on electric power, and thus the emission profile of the U.S. electricity grid is used to model the emissions associated with electric compressor operations. Finally, the estimated transport capacity of U.S. national gas pipelines (in ton-miles) is applied to the other pipeline variables in order to correlate pipeline emissions with pipeline distance.

2.5.6 Data for Other Energy Sources

The overall goal of this analysis is to understand the greenhouse gas burdens of natural gas extraction and transport. However, the modeling of the conversion of natural gas energy to electricity and electricity transmission is necessary in order to understand how significant extraction and transport are in the cradle-to-grave life cycle context. Additionally, including a comparison both to the upstream greenhouse gases from coal extraction and transport, and the conversion of coal to electricity allows comparison of the fuels on a common basis.

Coal was chosen as a comparable fossil energy source to natural gas that will be used for power production. Because a mix of natural gas sources is developed to represent a domestic production average, a similar method was followed for developing an average domestic coal extraction and transport profile. Two sources of coal are used in the mix, and a wide range of uncertainty is applied to sensitive parameters to ensure the domestic average is captured. The two coal sources are:

- Illinois No. 6 Underground-mined Bituminous
- Powder River Basin Surface-mined Sub-bituminous

Table 2-6 shows the properties used for each type of coal, as well as the proportion of U.S. supply used to create the average profile. The methane content is indicative of what is emitted to the atmosphere during the mining process, not the methane contained in the coal in the formation or after mining.

Table 2-6: Coal Properties

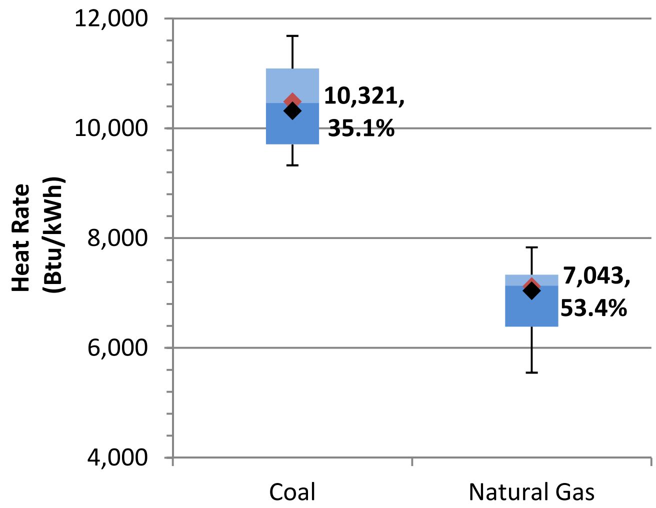
Coal Type	U.S. Supply Share (% by energy)	Energy Content (Btu/lb)	Carbon Content (% by mass)	Methane Emissions (cf CH_4/ton)
Sub-bituminous	69%	8,564	50.1%	8 – 98 (51)
Bituminous	31%	11,666	63.8%	360 – 500 (422)
Average		9,526	54.3%	

Additional information for the Illinois No. 6 profile can be found in the appendix and in the NETL document, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).* Additional information for the Powder River Basin coal extraction and transport profile can be found in the appendix to this document.

2.5.7 Data for Energy Conversion Facilities

The simplest way to compare the full life cycle of coal and natural gas is to produce electricity, although there are alternative uses for both feedstocks. To compare inputs of coal and natural gas on a common basis, production of baseload electricity was chosen. Seven different power plant options are used – three for natural gas and four for coal. Three of the options include carbon capture technology and sequestration infrastructure. Two of the options are U.S. fleet averages based on eGRID data, while the remainder are NETL baseline models. For the U.S. fleet average power plants, **Figure 2-3** shows the distribution of heat rates and associated efficiencies from eGRID. To arrive at the samples shown below, plants smaller than 200MW, with capacity factors lower than 60 percent, and with primary feedstock percentages below 85 percent were cut. The boxes are the first and third quartiles, and the whiskers the 5th and 95th percentiles. The division in the boxes is the median value. The black diamond is the mean, and the orange diamond is the production-weighted mean.

Figure 2-3: Fleet Baseload Heat Rates for Coal and Natural Gas (EPA, 2010)



2.5.7.1 Natural Gas Combined Cycle (NGCC)

The NGCC power plant is based a 555-MW thermoelectric generation facility with two parallel, advanced F-Class gas fired combustion turbines. Each combustion turbine is followed by a heat recovery steam generator that produces steam that is fed to a single steam turbine. The NGCC plant consumes natural gas at a rate of 75,900 kg/hr and has an 85 percent capacity factor. Other details on the fuel consumption, water withdrawal and discharge, and emissions to are detailed in NETL's bituminous baseline (NETL, 2010a). The carbon capture scenario for NGCC is configured a Fluor Econamine carbon dioxide capture system that recovers 90 percent of the CO_2 in the flue gas

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant (NETL, 2010d).*

2.5.7.2 Gas Turbine Simple Cycle (GTSC)

The GTSC plant uses two parallel, advanced F-Class natural gas-fired combustion turbines/generators. The performance of the GTSC plant was adapted from NETL baseline of NGCC power by considering only the streams that enter and exit the combustion turbines/generators and not accounting for any process streams related to the heat recovery systems used by combined cycles. The net output of the GTSC plant is 360 MW and it has an 85 percent capacity factor.

2.5.7.3 U.S. 2007 Average Baseload Natural Gas

The average baseload natural gas plant was developed using data from eGRID on plant efficiency (EPA, 2010). The most recent eGRID data is representative of 2007 electricity production. The average heat rate was calculated for plants with a capacity factor over 60 percent and a capacity greater than 200MW to represent those plants performing a baseload role. The average efficiency (weighted by production, so the efficiency of larger, more productive plants had more weight) was 53.4 percent. This heat rate is applied to the energy content of natural gas (which ranges from 990 and 1,030 Btu/cf) in order to determine the feed rate of natural gas per average U.S. natural gas power. Similarly, the carbon content of natural gas (which ranges from 72 percent to 80 percent) is factored by the feed rate of natural gas, 99 percent oxidation efficiency, and a molar ratio of 44/12 to determine the CO_2 emissions per unit of electricity generation.

2.5.7.4 Integrated Gasification Combined Cycle (IGCC)

The plant modeled is a 640 MW IGCC thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by a water quench. A slurry of Illinois No. 6 coal and water is fed to two parallel, pressurized, entrained flow gasifier trains. The cooled syngas from the gasifiers is cleaned before being fed to two advanced F-Class combustion turbine/generators. The exhaust gas from each combustion turbine is fed to an individual heat recovery steam generator where steam is generated. All of the net steam generated is fed to a single conventional steam turbine generator. A syngas expander generates additional power.

This facility has a capacity factor of 80 percent. For the carbon capture case, the plant is a 556 MW facility with a two-stage Selexol solvent process to capture both sulfur compounds and CO_2 emissions. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant (NETL, 2010c).*

2.5.7.5 Supercritical Pulverized Coal (SCPC)

This plant is a 550 MW facility located at a greenfield site in southeast Illinois utilizing a single-train supercritical steam generator. Illinois No. 6 pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional steam turbine generator. Air emission control systems for the plant include a wet limestone scrubber that removes sulfur dioxide, a combination of low-nitrogen oxides burners and overfire air, and a selective catalytic reduction unit that removes nitrogen oxides, a pulse jet fabric filter that removes particulates, and mercury reductions via co-benefit capture.

The carbon capture case is a 546 MW plant configured with 90 percent CCS utilizing an additional sulfur polishing step to reduce sulfur content and a Fluor Econamine FG Plus process. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).*

2.5.7.6 Existing Pulverized Coal (EXPC)

This case is an existing pulverized coal power plant that fires coal at full load without capturing carbon dioxide from the flue gas. This case is based on a 434 MW plant with a subcritical boiler that fires Illinois No. 6 coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. The net efficiency of this power plant is 35 percent.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant (NETL, 2010b).*

2.5.7.7 U.S. 2007 Average Baseload Coal

Using a similar method to the fleet average natural gas baseload plant, a mean and weighted average efficiency of 35.1 percent were pulled from eGRID. Using the coal characteristics detailed in **Table 2-6**, a feed rate and emissions rate were created.

For each option, the transmission and distribution (T&D) of electricity incurs a 7 percent loss, resulting in the production of additional electricity and extraction of necessary fuel to overcome this loss. All upstream life cycle stages scale according to this loss factor.

Construction is included in the four NETL developed models. It accounts for less than 1 percent of overall greenhouse gas impact, and so was excluded from the total for the fleet average plants.

The performance characteristics of the power plants modeled in this analysis are summarized in **Table 2-7**. Note that for the average natural gas and coal power plants, low, nominal and high values are indicated.

Table 2-7: Power Plant Performance Characteristics

Property			Natural Gas			Coal					
			NGCC	GTSC	Avg. NG	IGCC	IGCC (w/ CCS)	SCPC	SCPC (w/ CCS)	EXPC	Avg. Coal
Performance											
Net Output	MW		555	360	> 200	640	556	550	546	434	> 200
Heat Rate[1]	Btu/kWh	L			7,334						11,090
		N	6,798	11,323	7,043	8,756	10,458	8,687	12,002	9,749	10,321
		H			6,387						9,708
Efficiency	%	L			46.5%						30.8%
		N	50.2%	30.1%	48.4%	39.0%	32.6%	39.3%	28.4%	35.0%	33.1%
		H			53.4%						35.1%
Capacity Fac.	%		85%	85%	> 60%	80%	80%	85%	85%	85%	> 60%
Feedstocks											
Natural Gas	cf/MWh		6,619	11,025	6,858	-	-	-	-	-	-
Ill. No. 6 Coal	lb/MWh		-	-	-	730	876	745	1,036	734	649
PRB Coal	lb/MWh		-	-	-	-	-	-	-	-	355
Air Emissions											
CO_2	lb/MWh		804	1,100	817	1,723	206	1,768	244	2,075	1,999
CO_2 Capture	%		n/a	n/a	n/a	n/a	90%	n/a	90%	n/a	n/a

[1] L, N, H indicated Low, Nominal (default), and High values, respectively.

2.5.8 Summary of Key Model Parameters

The following table summarizes the key parameters that affect the life cycle results for the extraction of natural gas. This includes the amounts of methane emissions from routine activities, frequency and emission rates from non-routine operations, depths of different well types, flaring rates of vented gas, production rates, and domestic supply shares.

Table 2-8: Key Parameters for Six Types of Natural Gas Sources

Property (Units)	Onshore	Associated	Offshore	Tight Sands	Shale	CBM
Natural Gas Source						
Production Rate (Mcf/day) (Range)	66 (46 - 86)	121 (85 - 157)	2,800 (1,960 - 3,641)	110 (77 - 143)	274 (192 - 356)	105 (73 - 136)
Natural Gas Extraction Well						
Flaring Rate (%)	51% (41 - 61%)			15% (12 - 18%)		
Well Completion (Mcf/episode)	47			4,657	11,643	63
Well Workover (Mcf/episode)	3.1			4,657	11,643	63
Well Workover Frequency (Episode/well/yr)	1.1			3.5		
Liquids Unloading (Mcf/episode)	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading Frequency (Episodes/well)	930	n/a	930	n/a	n/a	n/a
Valve Emissions, Fugitive (lb CH_4/Mcf)	0.11		0.0001	0.11		
Other Sources, Point Source (lb CH_4/Mcf)	0.003		0.002	0.003		
Other Sources, Fugitive (lb CH_4/Mcf)	0.043		0.01	0.043		
Acid Gas Removal (AGR) and CO_2 Removal Unit						
Flaring Rate (%)	100%					
CH_4 Absorbed (lb CH_4/Mcf)	0.04					
CO_2 Absorbed (lb CO_2/Mcf)	0.56					
H_2S Absorbed (lb H_2S/Mcf)	0.21					
NMVOC Absorbed (lb NMVOC/Mcf)	6.59					
Glycol Dehydrator Unit						
Flaring Rate (%)	100%					
Water Removed (lb H_2O/Mcf)	0.045					
CH_4 Emission Rate (lb CH_4/Mcf)	0.0003					
Valves & Other Sources of Emissions						
Flaring Rate (%)	100%					
Valve Emissions, Fugitive (lb CH_4/Mcf)	0.0003					
Other Sources, Point Source (lb CH_4/Mcf)	0.02					
Other Sources, Fugitive (lb CH_4/Mcf)	0.03					
Natural Gas Compression at Gas Plant						
Compressor, Gas-powered Reciprocating (%)	100%	100%		100%	75%	100%
Compressor, Gas-powered Centrifugal (%)			100%			
Compressor, Electrical, Centrifugal (%)					25%	
Natural Gas Emissions on Transmission Infrastructure						
Pipeline Transport Distance (mi.)	604 (483 - 725)					
Pipeline Emissions, Fugitive (lb CH_4/Mcf-mi.)	0.0003					
Natural Gas Compression on Transmission Infrastructure						
Distance Between Compressors (mi.)	75					
Compressor, Gas-powered Reciprocating (%)	78%					
Compressor, Gas-powered Centrifugal (%)	19%					
Compressor, Electrical, Centrifugal (%)	3%					

3 Inventory Results

This section includes upstream results for the average production case, marginal upstream results, and results after conversion to electricity.

3.1 Average Upstream Inventory Results

This analysis defines upstream activities as the raw material acquisition and transport activities that are necessary for the delivery of fuel to a power plant. The results of this analysis include the upstream GHG emissions for natural gas. For the natural gas supply chain, upstream includes well operations and natural gas processing activities, as well as the pipeline transport of natural gas from the extraction site to a power plant.

Figure 3-1: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source

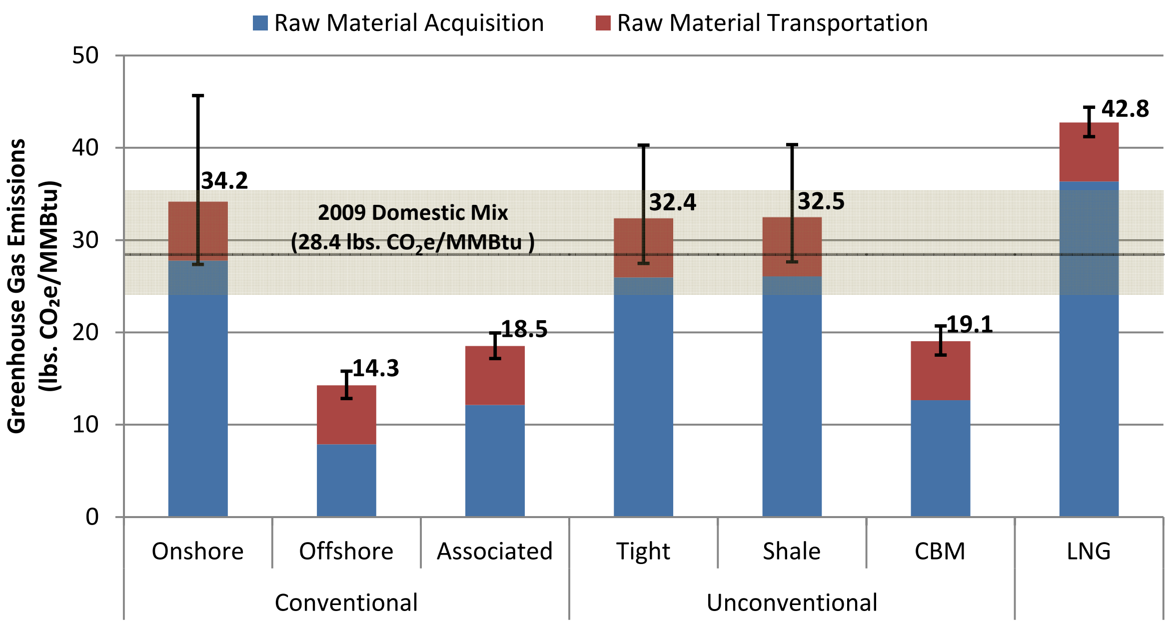


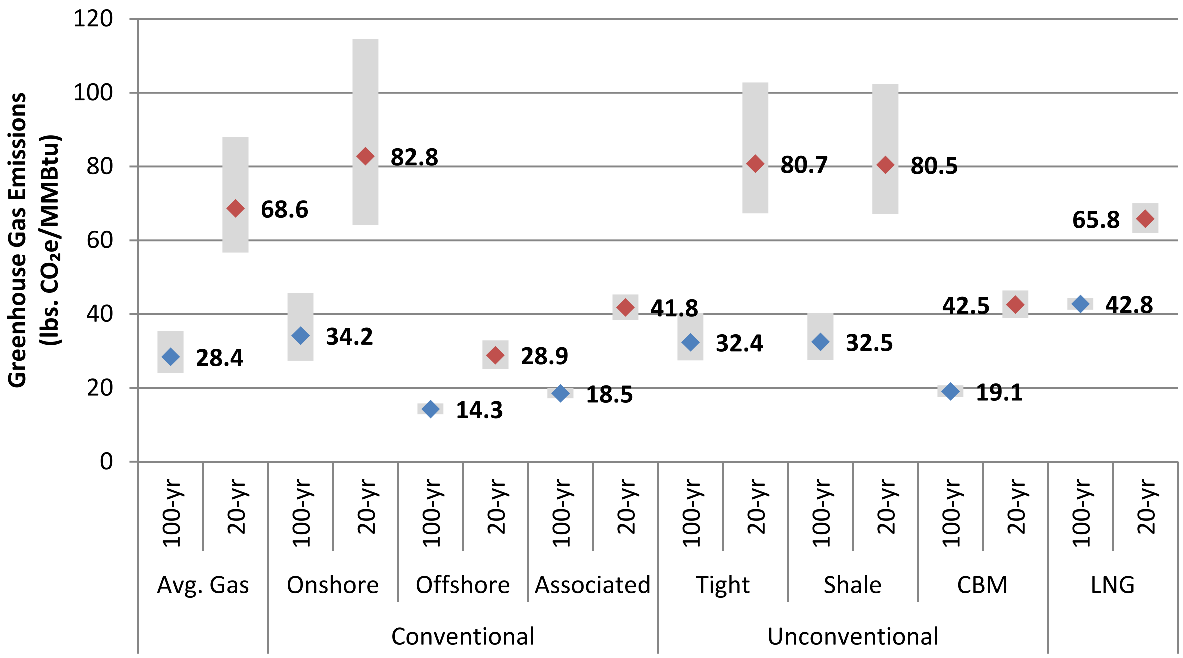
Figure 3-1 shows the comparative upstream greenhouse gases of the six sources of domestic gas, imported liquefied natural gas, and the 2009 mix of all of those sources, broken out by life cycle stage. These results are based on IPCC 100-year GWP. The domestic average of 28.4 lbs. CO_2e/MMBtu and its associated uncertainty are shown overlaying the results for the other types of gas. This average is calculated using the percentages shown in **Table 2-2**. It is worth noting here that the RMT result is the same for all types of natural gas. It is assumed in this study that natural gas is a commodity that is indistinguishable once put on the transport network, so the distance traveled is the same for all types of natural gas. The distance parameter is adjustable, so if a natural gas type with a short distance to markets were evaluated, the RMT value would be smaller.

Offshore sourced natural gas has the lowest greenhouse gases of any source. This is due to the very high production rate of offshore wells and an increased emphasis on controlling methane emissions for safety and risk-mitigation reasons.

Imported gas has a significantly higher greenhouse gases than even domestic unconventional extraction. It is fundamentally an offshore extraction process, which has the lowest GHGs of all the sources. The additional impact is due to the refrigeration, ocean transport and liquefaction processes. Uncertainty is highest for the unconventional sources due to high episodic emissions (well completions, workovers, etc.) and a wide range of observed production rates to allocate those emissions.

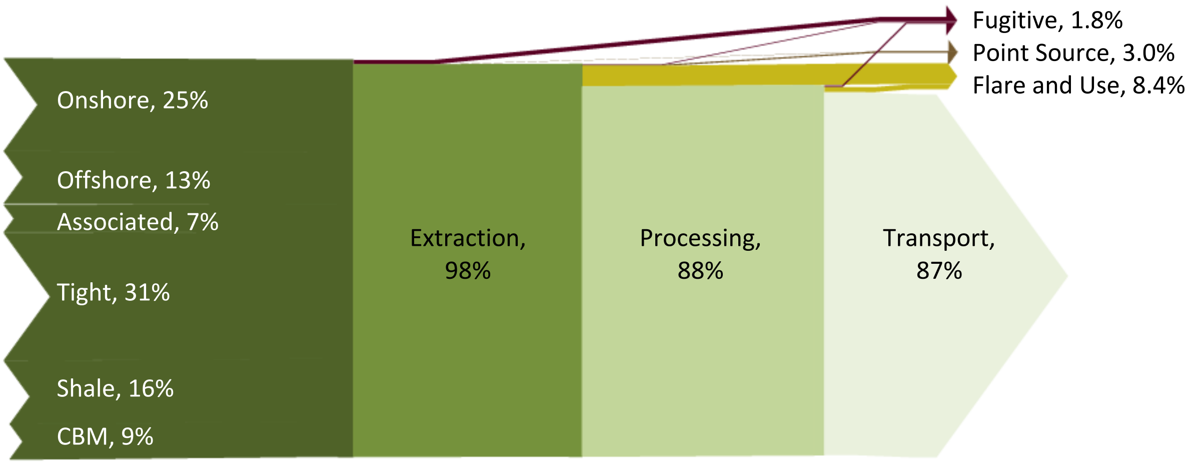
The key sources of GHG emissions in the natural gas supply chain are the combustion of fossil fuels and the venting of methane from natural gas processing and compression equipment.

Figure 3-2: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source and GWP



The results in **Figure 3-2** compare the basic results from **Figure 3-1** across two sets of global warming potentials (detailed in **Table 2-1**). Converting the inventory of greenhouse gases to 20-year GWP, where methane's factor increases from 25 to 72, magnifies the difference between conventional and unconventional sources of natural gas, and the importance of methane losses to the cradle-to-gate GHG results.

Figure 3-3: Cradle-to-Gate Reduction in Extracted Natural Gas



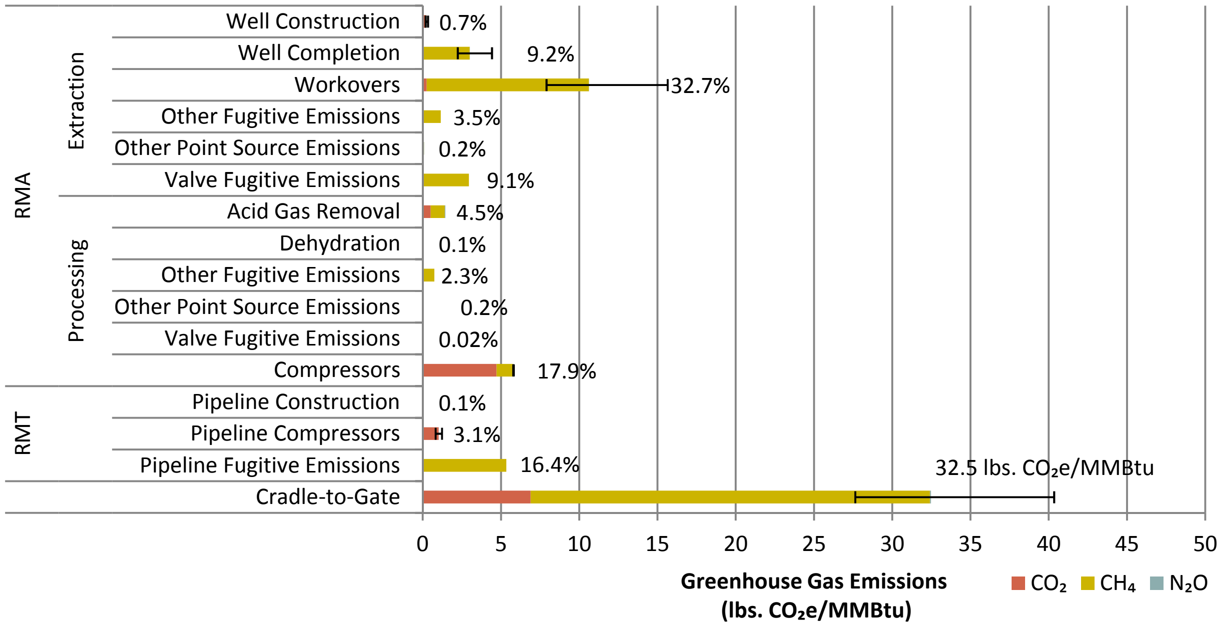
The Sankey diagram shown in **Figure 3-3** shows the reduction in natural gas (not solely methane) from extraction to delivery at the plant gate. This information is also not weighted by global warming potential. **Table 3-1** shows the same information in table form. Of the natural gas extracted from the ground, only 87 percent is delivered to the plant or city gate; 13 percent is either used internally for power, released at a point source and then flared – if applicable, or lost as a fugitive emission. It is important to recognize that not all of this gas is emitted to the atmosphere. In fact, 64 percent of the reduction in natural gas is used to power various processing equipment, most significantly compressors providing motive force for the natural gas. Further, 23 percent are point source emissions, generally concentrated enough to be flared; this, importantly from a climate change perspective, converts the methane to carbon dioxide. Only 13 percent of emissions are considered fugitive: spatially separated emissions difficult to capture or control.

Table 3-1: Natural Gas Losses from Extraction and Transportation

Process	Raw Material Acquisition		Transport	Total
	Extraction	Processing		
Extracted from Ground	100.0%			100.0%
Fugitive Losses	1.2%	0.1%	0.5%	1.8%
Point Source Losses (Vented or Flared)	0.8%	2.2%	0.0%	3.0%
Flare and Fuel Use	0.0%	7.6%	0.8%	8.4%
Delivered to End User				86.9%

By expanding the underlying data in NETL's model, a better understanding of the key contributions to natural gas emissions can be achieved. **Figure 3-4** shows the GHG contribution of specific extraction and transport activities for the Barnett Shale profile. This figure further shows the contribution of methane (CH_4), nitrous oxide (N_2O) and carbon dioxide (CO_2) to the total greenhouse gases. Similar data exists for each source of natural gas, as well as for the domestic average.

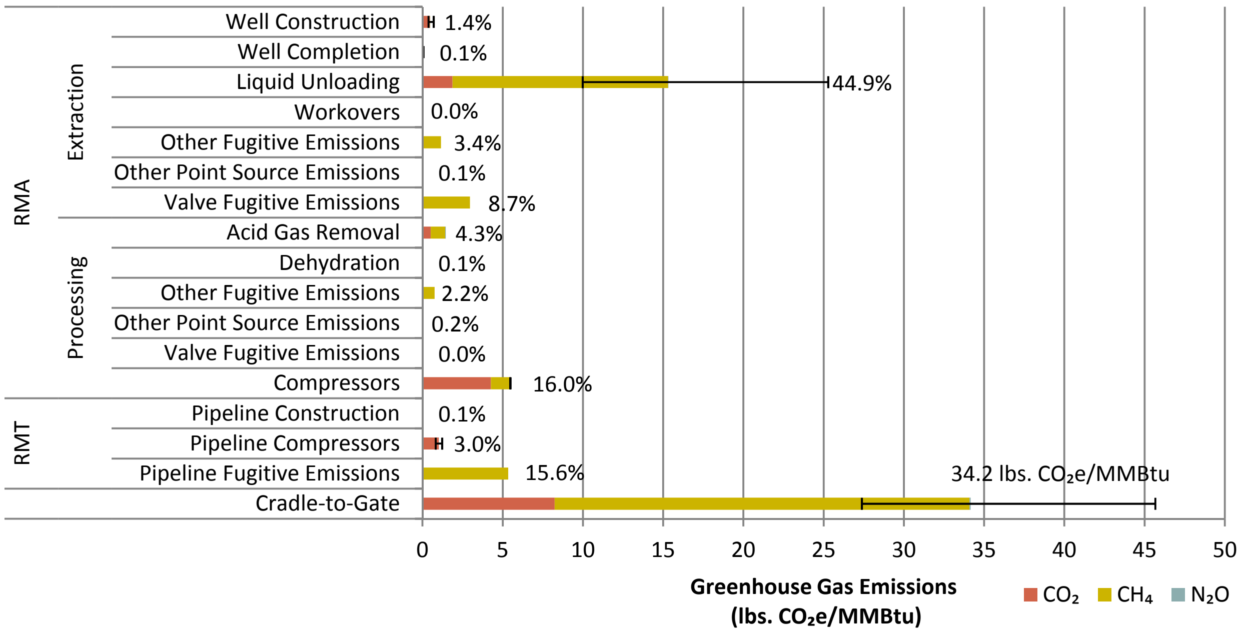
Figure 3-4: Expanded Greenhouse Gas Results for Barnett Shale Gas



This figure shows clearly how important methane is to the total greenhouse gas emissions. In most energy systems, carbon dioxide is the primary concern, but for natural gas extraction, processing and transport, the methane drives the result, and most of the uncertainty. With this unconventional gas, the importance (and associated uncertainty) associated with episodic emissions such as well completion and workover can be seen as well. Well construction, on the other hand, contributes less than 1 percent to the total. Moreover, from the compressors at the last stage of the processing step along with the compressor operations and fugitive emissions on the pipeline, the importance of transport can be seen from these results.

Figure 3-5 shows similar cradle-to-gate results for the natural gas extracted from conventional onshore wells. As with the shale profile, the major contributors are the fuel use and fugitive emissions from the transport, and episodic emissions like liquid unloading. Liquid unloading along contributes 45 percent to the total emissions, and the majority of the uncertainty as well. The uncertainty indicated here is due to a wide range in production rate, not the emission factor for liquids unloading. As discussed in the modeling method, production rate is used to apportion episodic emissions.

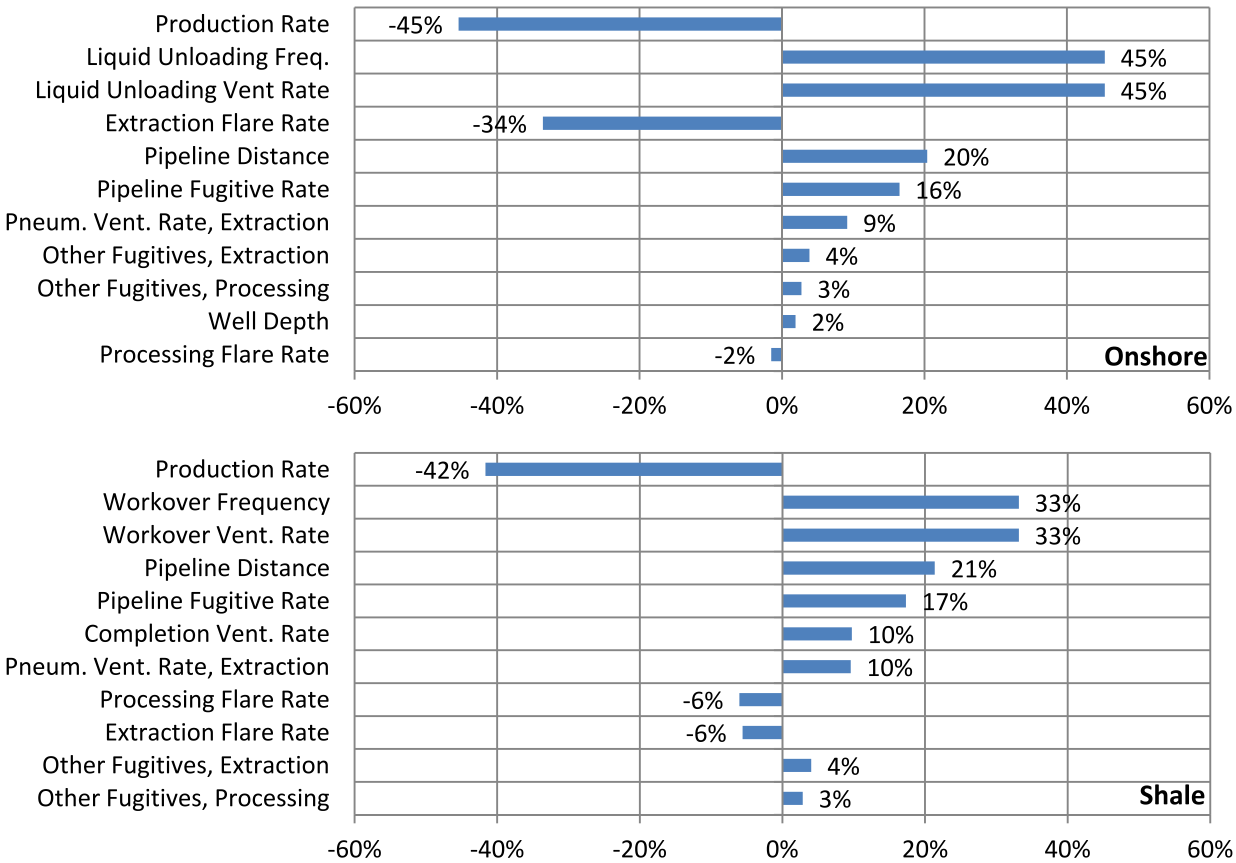
Figure 3-5: Expanded Greenhouse Gas Results for Onshore Natural Gas



This analysis uses a parameterized modeling approach that allows the alteration and subsequent analysis of key variables. Doing so allows the identification of variables that have the greatest effect on results. Sensitivity results are shown in **Figure 3-6**. Parameters were adjusted and displayed regardless of whether uncertainty information was collected for that parameter. Percentages above are relative to a unit change in parameter value; all parameters are changed by the same percentage, allowing comparison of the magnitude of change to the result across all parameters. Positive results indicate that an increase in the parameter leads to an increase in the result. A negative value indicates an inverse relationship; an increase in the parameter would lead to a decrease in the overall result.

For example, a 5 percent increase in shale Production Rate would result in a 2.1 percent (5 percent of 42 percent) decrease in cradle-to-gate GHGs, from 32.5 to 31.8 lbs. CO_2e/MMBtu. A corresponding 5 percent increase in onshore Production rate results in a 2.3 percent decrease to 33.4 lbs. CO_2e/MMBtu. Thus, onshore is more sensitive to changes in production rate than shale gas.

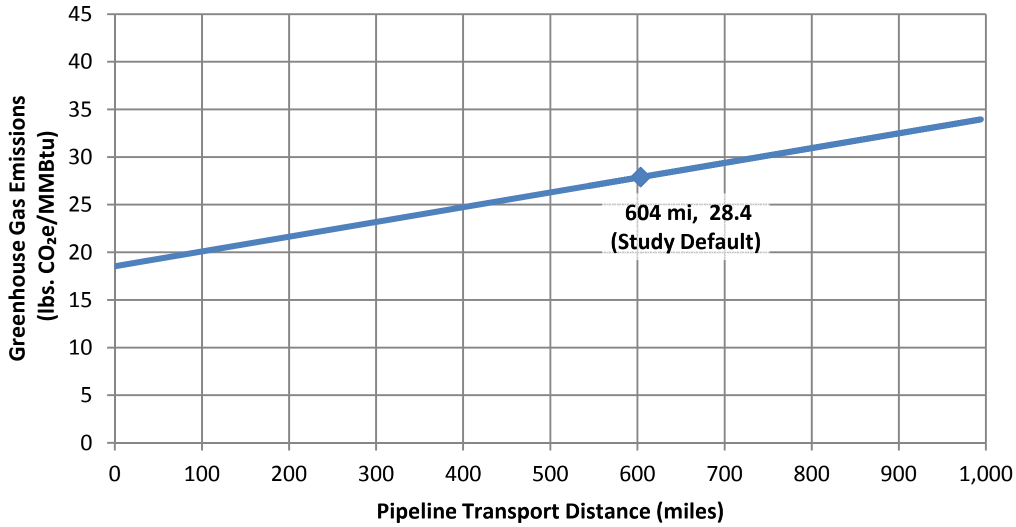
Figure 3-6: Sensitivity of Onshore and Shale GHGs to Changes in Parameters



The results in **Figure 3-6** show that both the onshore and shale profiles are sensitive to changes in pipeline distance, which is currently set to 604 miles for all profiles. As more unconventional sources like Marcellus shale which is close to major demand centers (New York, Boston, Toronto) come on the market, the average distance natural gas has to travel will go down, decreasing the overall impact.

The pipeline transport of natural gas is inherently energy intensive because compressors are required to continuously alter the physical state of the natural gas in order to maintain adequate pipeline pressure. Further, the majority of compressors on the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline. **Figure 3-7** shows the sensitivity of natural gas losses to pipeline distance. The study default for domestic sources of natural gas is 604 miles, which was determined by solving for the distance at which the per-mile emissions were equivalent to the U.S. annual natural gas transmission methane emissions in 2009. See **Appendix A** for full discussion on determining a default distance.

Figure 3-7: Sensitivity of GHGs Results to Pipeline Distance



3.2 Results for Marginal Production

Marginal production is defined here as the next unit of natural gas produced not included in the average, presumably from a new, highly productive well for each type of natural gas. Since older, less productive wells are ignored as part of these results, the production rate per well is much higher, episodic emissions are spread across more produced gas, and the corresponding GHG inventory is lower. **Table 3-2** shows the production rate assumptions used for both the average and marginal cases.

Table 3-2: Production Rate Assumptions for Average and Marginal Cases

Source	Well Count	Dry Production (Tcf)	Production Rate (Mcf/day)					
			Average			Marginal		
			N	L (-30%)	H (+30%)	N	L (-30%)	H (+30%)
Onshore	216,129	5.2	66	46	86	593	297	1,186
Offshore	2,641	2.7	2,801	1,961	3,641	6,179	3,090	12,358
Associated	31,712	1.4	121	85	157	399	200	798
Tight Sands	162,656	6.6	111	78	144	110	77	143
Shale	32,797	3.3	274	192	356	274	192	356
CBM	47,165	1.8	105	73	136	105	73	136

Results are shown below in **Table 3-3**. The marginal and average production rates for the unconventional sources (tight, shale and CBM) were identical, and so there is no change shown below. There was a significant change in the production rate for all the mature conventional sources. Large numbers of the wells from each of these sources are nearing the end of the useful life, and have dramatically lower production rates, bringing the average far below what would be expected of a new well of each type.

Table 3-3: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

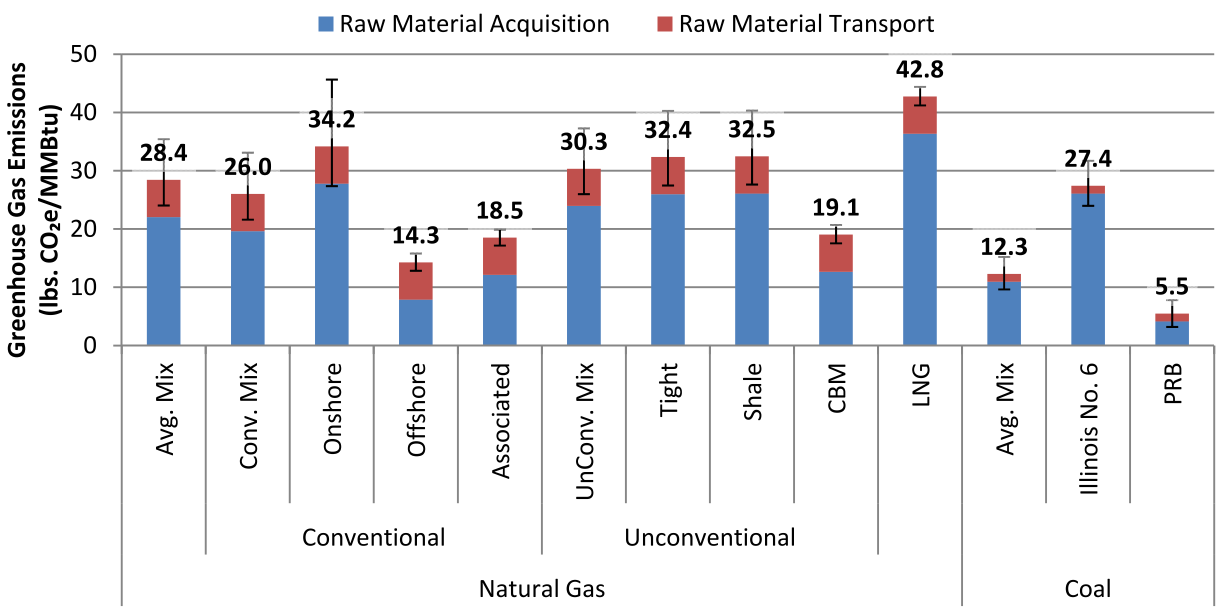
Interestingly, although the production rates for both associated gas and offshore gas change significantly, there is little change to the upstream value: a drop of 0.8 percent and 1.4 percent respectively. This has to do with the characteristics of these types of wells; the flow of natural gas in offshore wells is so strong that there is no need to periodically perform liquids unloading, and for associated wells, the petroleum co-product is constantly removing any liquid in the well. This means the only episodic emission (one which would need to be allocated by lifetime production of the well) is the construction or completion of the well, which is small in both cases, as a percentage of overall emissions.

That leaves onshore conventional production as the only source which shows a significant difference (a drop of 41.2 percent) between the average and marginal production. There are over 200,000 active onshore conventional wells, over 80 percent of which have daily production below the average rate of 138 Mcf/day (EIA, 2010). Yet, when this marginal natural gas is run through electricity generation, there is only a 7 percent drop in greenhouse gas emissions.

3.3 Comparison to Other Fossil Energy Sources

Additional insight can be gained by comparing the life cycle of natural gas power to those of coal. The upstream GHG emissions for various fuels are shown in **Figure 3-8**.

Figure 3-8: Comparison of Upstream GHG Emissions for Various Feedstocks

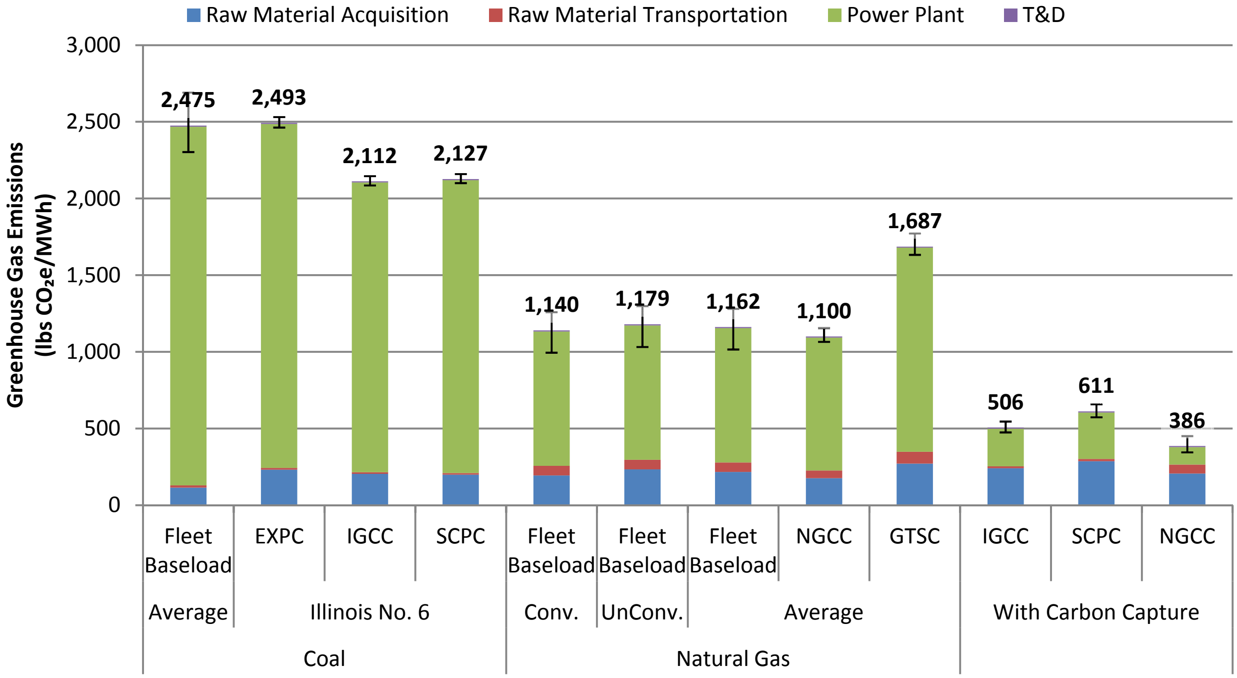


Compared on an upstream energy basis, natural gas has higher GHG emissions than coal. Comparing the domestic mixes from **Figure 3-8**, natural gas is nominally 116 percent more greenhouse gas intense than coal. Gassier bituminous coal such as Illinois No. 6 is more comparable, but only makes up 31 percent of domestic consumption on an energy basis.

3.4 Role of Energy Conversion

The per unit energy upstream emissions comparisons shown above are somewhat misleading in that a unit of coal and natural gas often provide different services. If they do provide the same service, they often do so with different efficiencies—it is more difficult to get useful energy out of coal than it is out of natural gas. To provide a common basis of comparison, different types of natural gas and coal are run through various power plants and converted to electricity. Note that there are alternative uses of both fuels, and as such, different bases on which they could be compared. However, in the United States, the vast majority of coal is used for power production, and so provides the most relevant comparison. **Figure 3-9** compares results for natural gas and coal power on the basis of 1 MWh of electricity delivered to the consumer. In addition to the NETL baseline fossil plants with and without carbon capture and sequestration, these results include a simple cycle gas turbine (GTSC) and representations of fleet average baseload coal and natural gas plants, as described in **Section 2.5.7**.

Figure 3-9: Life Cycle GHG Emissions for Electricity Production



In contrast to the upstream results, which showed a significantly higher GHGs for natural gas than coal, these results show that natural gas power, on a 100-year GWP basis, has a much lower impact than coal power without capture, even when using unconventional natural gas. Even when using less efficient simple cycle turbines, which provide peaking power to the grid, there are far fewer greenhouse gases emitted than for coal-fired power. Because of different the different roles played by these plants, the fairest comparison is the domestic mix of coal run through an average baseload coal power plant with the domestic mix of natural gas run through the average baseload natural gas plant. In that case, the coal-fired plant has emissions of 2,475 lbs. CO_2e/MWh, more than double the emissions of the natural –gas fired plant at 1,162 lbs. CO_2e/MWh.

Figure 3-10 shows the same results but applying and comparing 100- and 20-year IPCC global warming potentials to the inventoried greenhouse gases.

Figure 3-10: Comparison of Power Production GHG Emissions on 100- and 20-year GWPs

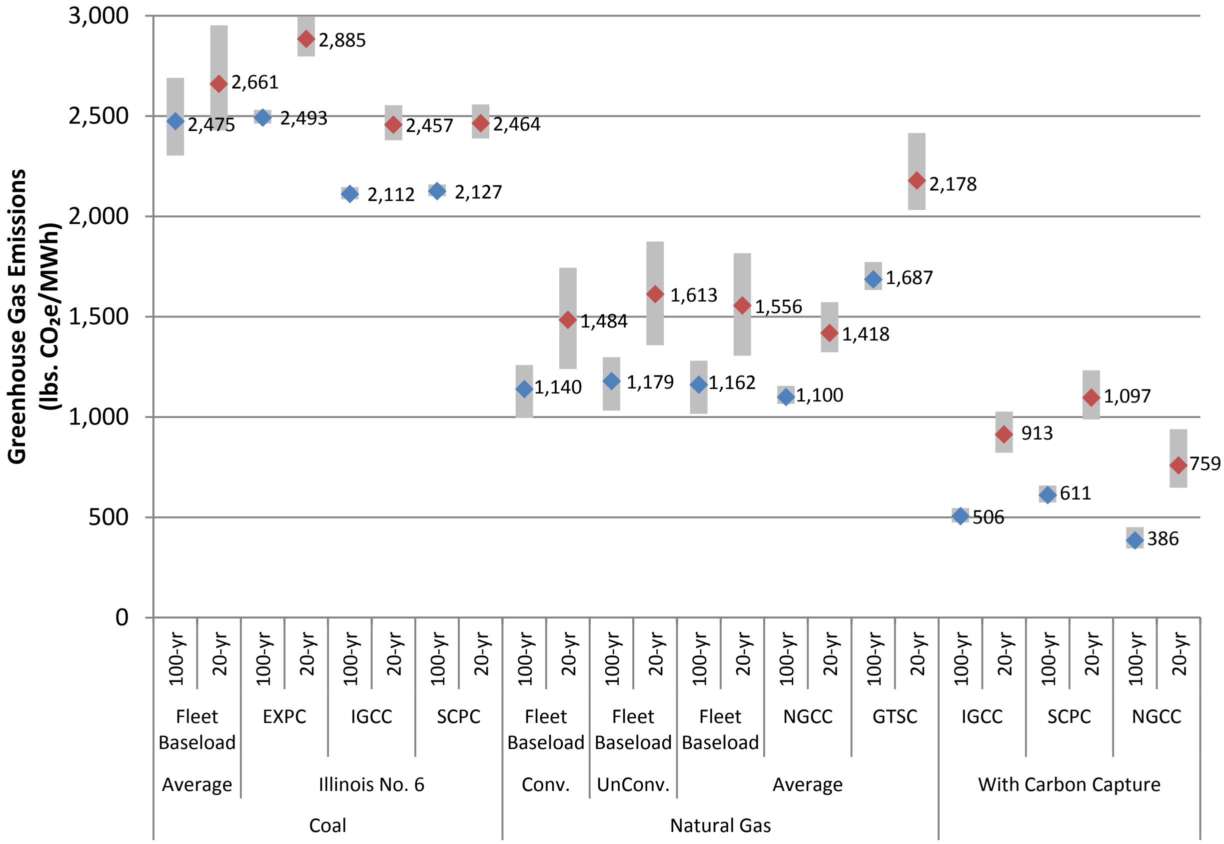


Figure 3-10 shows that even when using a GWP of 72 for CH_4 to increase the relative impact of upstream methane from natural gas, gas-fired power still has lower GHGs than coal-fired power. This conclusion holds across a range of fuel sources (conventional vs. unconventional for natural gas, bituminous vs. average for coal) and a range of power plants (GTSC, NGCC, average for natural gas, and IGCC, SCPC, EXPC, and average for coal). The one situation where this conclusion changed is the use of unconventional natural gas in an NGCC unit with carbon capture compared to an IGCC unit with carbon capture. The high end of the range overlaps the nominal value for IGCC in this situation.

4 Discussion

The following section contains a comparison of the results of this analysis to other natural gas LCAs, a discussion on data limitations, recommendations for improvement and final conclusions.

4.1 Comparison to Other Natural Gas LCAs

Authors at universities and other government labs have conducted research on the natural gas life cycle. The methods and conclusions of three such papers are summarized below.

Life Cycle Assessment of a Natural Gas Combined Cycle Power Generation System (Spath & Mann, 2000)

This NREL study is somewhat dated, having been published in 2000, but using data from the 1990s. It is a high quality study, which makes solid assumptions and tests those assumptions with documented sensitivity analysis. It uses national, annual, top-down information to develop the upstream emissions for natural gas extraction and transportation. Because of this, there are no data specific to unconventional extraction. This study includes not only greenhouse gases but select criteria air emissions and an energy balance. A qualitative impact assessment is performed as well.

Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation (Jaramillo, Griffin, & Matthews, 2007)

This widely cited paper is the most recent publicly available, peer-reviewed study that directly compares life cycle greenhouse gas emissions of power generated from natural gas and coal. Due to concerns regarding gas price volatility at the time the paper was being written, it also includes a comparison of LNG and synthetic natural gas (SNG) from coal. Rather than attempting to represent the next megawatt-hour generated by using best available technology, it looks at average current megawatt-hours generated, so plant efficiencies tend to be lower and emission factors higher. It mixes technologies (NGCC vs. GTSC) and roles (baseload vs. peaking). Like the NREL study, the upstream emissions for both natural gas and coal are top-down numbers. These values are somewhat dated, and represent a homogeneous gas supply rather than breaking out unconventional extraction.

Development of a Top Down Screening Model Using 2011 EPA Greenhouse Gas Inventory

Although this study uses emission factors from the EPA that went into building the 2011 U.S. Greenhouse Gas Inventory, it did not use the annual emissions estimates to generate a top-down value. Rather, some of the EPA emission factors were applied against specific activities, combined with other data sources and standard engineering calculations in a comprehensive hybrid bottom-up approach.

For comparison purposes, NETL performed a top-down analysis of 2009 domestic natural gas production using EPA's 2011 GHG inventory. This top-down approach was not a comprehensive LCA, but was a screening method that resulted in an aggregated, national-level estimate of GHG emissions. The top-down approach gave a GHG result of 36.6 lbs. CO_2e/MMBtu of delivered natural gas to a large end user, with +30 percent and -19 percent uncertainty. NETL's comprehensive LCA model of natural gas gives a GHG result of 28.4 lbs. CO_2e/MMBtu of delivered natural gas, which is 24 percent lower than the top-down value derived from EPA's national inventory. The nominal top-down number from EPA's inventory is within NETL's uncertainty range, but NETL and EPA use many of the same emission factors for natural gas production, and thus an explanation of the 24 percent difference is necessary.

An overarching reason for the difference between EPA's national inventory and NETL's natural gas life cycle analysis model is that EPA's inventory is based on the emissions reported for an entire industry sector over one year, while NETL's model accounts for the operating characteristic of six types of natural gas extraction technologies over a 30-year period and then mixes the six types according to the 2009 U.S. natural gas supply profile. Three specific examples of this fundamental difference between modeling approaches are as follows:

1. A difference in method between activity-based scaling to the national level vs. well-specific production rates that scale results to each of six extraction types.
2. Differences in episodic emission factors for tight gas and the contribution of tight gas to the national inventory.
3. Time series discrepancies inherent in EPA's episodic emission factors.

Clarification on these differences is provided below.

For each type of natural gas well, NETL apportions episodic emission factors based on the production rate of a single well. These apportioned emissions are then compiled according to the relative contribution of each well type to the domestic mix to arrive at the domestic average emissions. EPA's national GHG inventory, on the other hand, does not use well production rates, but uses well activity counts for conventional and unconventional wells to scale up the episodic emission factors to a national level. It is possible that the production rates of the wells that were sampled during the development of EPA's episodic emission factors do not align with the average well production rates applied by NETL. Or the activity counts used by EPA do not align with the contribution of the six natural gas types to the national mix as modeled by NETL.

When modeling tight gas, NETL made adjustments to EPA's emission factors for well completions and workovers. A close look at EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emission factors are representative of high-pressure, tight gas wells in the San Juan and Piceance Basins that were completed using a horizontal hydraulic fracturing method and have a high, for tight gas basins, EUR of approximately 2 to 4 BCF. NETL's survey of tight gas production in the U.S. determined that an EUR of 1.2 BCF is more representative of average U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. NETL uses an emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells. It is worth noting that EPA does not distinguish between tight sands and shale gas in the annual inventory, a general category of unconventional natural gas is characterized by low and high pressure formations. NETL applied EPA's unconventional completion and workover emission factor for low pressure formations (49.57 Mcf CH_4) reported in Subpart W Technical Support Document (EPA, 2011a) to the coal bed methane well profile and the corresponding high pressure well emission factor to shale gas based on the correlation of representative EUR of 3 BCF for Barnett Shale and the San Juan and Piceance Basin EUR's representing a range of 2 to 4 BCF. While the EPA Subpart W Technical Support Document detailed the results for unconventional well completions and workovers for low pressure formations, the annual inventory (EPA, 2011a) discusses unconventional well activity as a single category assumed to be completed by hydraulic fracture, for the purposes of the inventory, and applies the high pressure formation emission factor of 9,175 Mcf CH_4 for all unconventional well completions and workovers in the annual activity count.

The differences between the top-down and comprehensive approaches is further influenced by whether or not EPA explicitly accounts for tight gas production or simply includes tight gas within its conventional onshore natural gas activity factors. Tight gas represents 31 percent of the 2009 U.S. domestic natural gas supply, and thus the results for NETL's domestic mix are sensitive to changes in the tight gas results (the extent of this sensitivity is demonstrated by the tornado chart for the domestic natural gas mix). It is not clear if EPA includes tight gas within its conventional or unconventional category. If EPA accounts for tight gas in its conventional category, then liquids unloading would be incorrectly assigned to tight gas production, which would result in an overstated result. Alternatively, if EPA accounts for tight gas in its unconventional category, then a well completion and workover emission factor based on high production tight gas formations using horizontal hydraulic fracture was applied, which would result in an overstated result. This difference is only relevant in the comparative context between the two modeling approaches (screening versus comprehensive life cycle analysis). With respect to the purpose of the EPA national inventory approach, the effects are minimized based on the granularity of the overall analysis and the comparison of results at the national sector level. As described above, NETL adjusted the episodic emission factors for tight gas and coal bed methane based on well completion method and production profile.

EPA's documentation of unconventional emission factors are provided in its Subpart W document, which is the basis for its national inventory results (EPA, 2011a). EPA's 2009 GHG inventory is representative of 2009 natural gas production; however, a close look at EPA's Subpart W document reveals that the episodic emission factors are based on relatively small samples of natural gas wells from 2006 and 2007. It is common for LCAs to use data from a broad range of years. However, the behavior of the natural gas industry was especially volatile between 2007 and 2009. The imposition of emission factors that are representative of 2006 and 2007 upon other natural gas data that are representative of anomalous activity in 2009 creates a time-series lag that introduces uncertainty to the emission factor.

Figure 4-1: Natural Gas Well Development vs. Natural Gas Production (EIA, 2011b, 2011c)

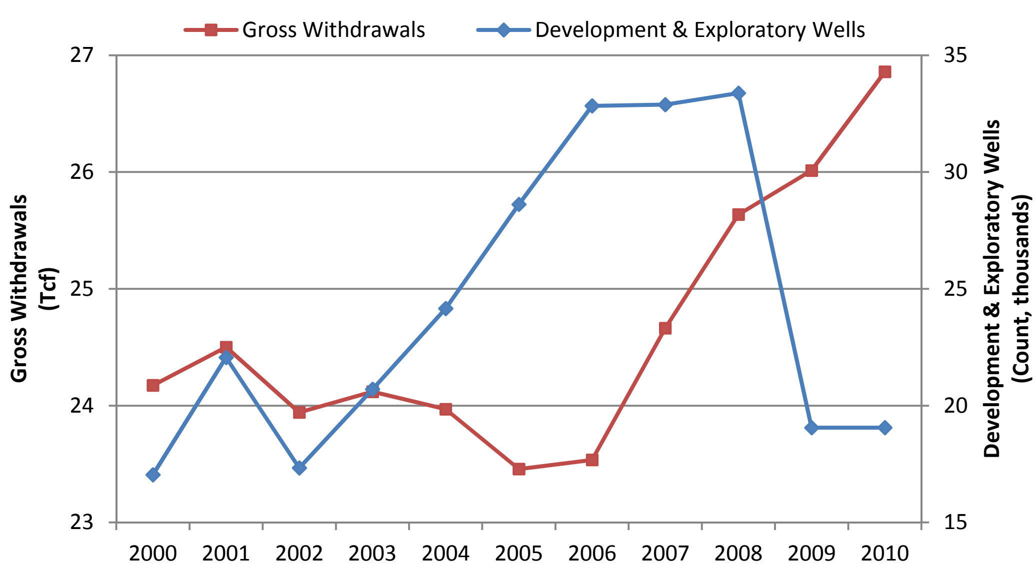


Figure 4-1 shows how increases in natural gas withdrawals lag between five and six years behind the increase in natural gas well drilling activity. Using a numerator with 2006 to 2007 data for well

activity, and 2009 data for withdrawals for the numerator could cause an undefined level of uncertainty in the emission factor. The modeling approaches used by EPA and NETL (as described in the first item above) react differently to this time-series lag. It is possible that NETL's model diminishes these effects because it amortizes the emissions over a 30-year operating period. **Table 4-1** shows the differences among key parameters of the NETL and EPA models.

Table 4-1: Parameter Comparison between NETL and EPA Natural Gas Modeling

Property[1]	Units	NETL						EPA	
		Onshore	Assoc.	Offshore	Tight Sands[2]	Barnett Shale	CBM[3]	Conv.	Unconv.
Contribution to 2009 Mix	Percent	25%	7%	13%	31%	16%	9%	n/a	n/a
Production Rate (30-yr average)	Mcf/day	66	121	2,800	110	274	105	n/a	n/a
Active Wells (2007)	Count	n/a	n/a	n/a	n/a	n/a	n/a	431,035	41,790
Flaring Rate at Well	Percent	51%	51%	51%	15%	15%	51%	51%	15%
Completion Emissions	Mcf CH_4/episode	36.7	36.7	36.7	3,670	9,175	49.6	36.7	9,175
Workover Emissions	Mcf CH_4/episode	2.5	2.5	2.5	3,670	9,175	49.6	2.5	9,175
Workover Frequency	Episodes/year	0.04	0.04	0.04	0.12	0.12	0.12	0.04	0.12
Liquids Unloading Emissions	Mcf CH_4/episode	18.5	n/a	18.5	n/a	n/a	n/a	18.5	n/a
Liquids Unloading Frequency	Episodes/year	31	n/a	31	n/a	n/a	n/a	31	31

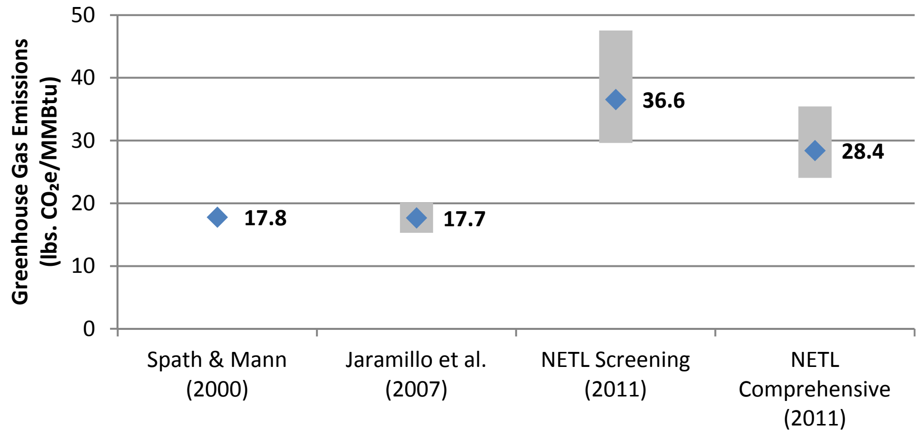
Figure 4-2 shows comparative greenhouse gas emissions from the three studies reviewed above. Results from each study were converted to a common basis of 100-year Global Warming Potential in pounds CO_2e per MMBtu gas delivered. The NREL study did not have an explicit range of values, so the central estimate is shown. For Jaramillo et al., the central estimate is the average of the high and low values.

[1] All emission rates are prior to flaring.

[2] The tight sands emission factor for well completions and workovers was calculated by NETL by reducing EPA's completion and workover factor (3,670 Mcf CH_4) for unconventional wells. The emission rates for completions and workovers are associated with the production rates and reservoir pressures of a well.

[3] The CBM emission factor for well completions and workovers (49.57 Mcf CH_4) is from EPA's documentation of low pressure wells. While CBM wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have lower emission rates from completions and workovers.

Figure 4-2: Comparison of Natural Gas Upstream GHGs from Other Studies



4.2 Data Limitations

A key objective of an LCA is to normalize all data to a common basis (the functional unit). Like all LCAs, this analysis is limited by data uncertainty and data limitations. Key instances of data uncertainty and limitation are summarized below.

4.2.1 Data Uncertainty

Episodic emissions, natural gas production rates, flaring rates, and pipeline distance are four areas of data uncertainty in this analysis and represented within the study results.

Episodic emission factors include the non-routine release of natural gas during well completion, workovers, and liquid unloading. The results of this analysis are sensitive to these episodic emissions. The data for episodic emissions from natural gas wells is limited to a relatively small sample of wells and includes data going back as far as 1996 (EPA, 2011a). These emission factors are not necessarily applicable to all natural gas wells. For instance, it is likely that some unconventional wells have been completed using best practices and thus have low completion emissions, while some conventional wells have been completed with poor practices and thus have high completion emissions. However, there is no basis for claiming that a more recent, larger sampling of natural gas wells would increase or decrease these emission factors.

This analysis uses the production rate for each type of natural gas well for apportioning episodic emissions to a unit of natural gas production. The production rates of unconventional natural gas wells (Barnett Shale, tight gas, and CBM wells) are based on estimated ultimate recovery (EUR) data that are specific to each formation and have specific geographical constraints (Lyle, 2011). Representativeness of unconventional production rate data provides a reasonable confidence range of +/-30 percent. Production data for conventional wells is more variable, exhibiting a 200 percent increase from the low to high production rates. This variability is due to the broad range in age, reservoir, and technology characteristics for conventional wells, making it difficult to define a "typical" conventional natural gas well.

Flaring rate is the portion of vented natural gas that is combusted; the unflared portion is released directly to the atmosphere. Conventional wells flare 51 percent of vented gas, while unconventional wells flare 15 percent of vented natural gas (EPA, 2011a). The natural gas processing plant is modeled at a 100 percent flaring rate. While technology is available to capture and flare virtually all of the vented natural gas from extraction and processing, economics and other practical concerns often prevent the implementation of such technologies. To account for uncertainty, this analysis varied the default values for flaring rates by +/-20 percent. It is likely that there are natural gas wells that fall outside of this range; however, based on professional judgment, we expect this range to account for average natural gas production.

The transmission of natural gas by pipeline involves the combustion of a portion of the natural gas in compressors as well as fugitive losses of natural gas. The total natural gas combustion and fugitive emissions is a function of pipeline distance, which was estimated at an average distance of 604 miles. This distance is based on the characteristics of the entire transmission network and delivery rate for natural gas in the U.S. It is possible that some natural gas sources are located significantly closer to their final markets than other sources of natural gas. To account for this uncertainty, this analysis varies the average pipeline distance by +/- 20 percent, which is an uncertainty range based on professional judgment.

4.2.2 Data Availability

Most data required for this analysis were readily available. However, there are several instances for which more detailed data would enhance the functionality of the LCA model and allow further discernment among natural gas types.

- Formation-specific gas compositions (CH_4, H_2S, NMVOC, and water) for each natural gas type would allow the assignment of specific venting emissions for natural gas extraction and processing. It would also allow the calculation of the specific heat load required for natural gas processing equipment (acid gas removal and dehydration).
- The effectiveness of green completions and workovers would allow further scrutiny of the episodic emissions at wells and, possibly, further data granularity among the three unconventional well types (Barnett Shale, tight gas, and CBM wells).
- No data are available for the fugitive emissions from around wellheads (between the well casing and the ground). This is a possible emission source that could present a significant opportunity for reductions in natural gas losses at a specific wellhead or site, but is not expected to be a significant contribution from an average natural gas perspective.
- Data for water sourcing and production of other fluids used for hydraulic fracturing would expand the boundaries of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Direct and indirect GHG emissions from land use from access roads and well pads would expand the scope of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Data for the energy requirements of natural gas exploration would allow further comparisons between conventional and unconventional natural gas. Historically, conventional natural gas fields have been difficult to find, but relatively easy to develop once they are located (NGSA, 2010). In contrast, unconventional gas fields are easy to find, but require significant preparation before natural gas is recovered.

- The energy requirements for the treatment of flowback water from the hydraulic fracturing of unconventional wells would represent an environmental burden that could allow further differentiation among natural gas extraction types.
- The current EPA GHG inventory data for natural gas pipeline emissions includes methane emissions in one category. A split between venting and fugitive emissions from pipeline transport would facilitate recommendations for reducing pipeline losses. Vented emissions may present opportunities for recovery, while fugitive emissions may not represent feasible opportunities for recovery.

4.3 Recommendations for Improvement

Creating a greenhouse gas inventory from a life cycle perspective gives not only a more complete picture of the impact of the process in question, but also allows for identification for the areas of largest impact, and those with the greatest opportunity for improvement. Since this inventory is presented on two different bases, opportunities were identified in both the extraction and delivery of natural gas as well as the production of electricity from natural gas and coal.

4.3.1 Reducing the GHG Emissions of Natural Gas Extraction and Delivery

Unconventional gas sources (shale, tight sands, coal bed methane, etc.) now make up the majority of natural gas extraction. As such, the emissions released during well completion and periodic well workovers are a major contributor to the overall greenhouse gas footprint, and a large opportunity for reduction. However, due to the relatively recent development of unconventional resources, better data is needed to characterize this opportunity based on basin type, drilling method, and production in order to better identify the potential for reductions.

Transportation of processed natural gas to the point at which it is consumed – in this inventory, large end users such as power plants – makes up a large portion of the overall upstream impact. There are two components to this impact: the first is the use of energy to compress the natural gas – the initial compression to put the natural gas on the pipeline, and then periodic compression as the motive force to push the natural gas along the transmission system. The second component is fugitive emissions from joints in the pipeline and other equipment. Improving compressor efficiency not only increases the amount of sellable product, but reduces the greenhouse gases emitted delivering that product. Pipeline fugitive emissions could be reduced with both technology and best management practices.

4.3.2 Reducing the GHG Emissions of Natural Gas and Coal-fired Electricity

Although efforts to reduce methane emissions from natural gas and coal extraction and transportation are important and should be continued, most GHG emissions from their extraction, transportation and use comes in the form of post-combustion carbon dioxide. Three high-level opportunities for reducing these emissions include:

- Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir
- Improve existing power plant efficiency
- Invest in advanced power research, development, and demonstration

Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

4.4 Conclusions

This greenhouse gas (GHG) analysis inventories six different sources of natural gas, including three types of unconventional gas, combines them into a domestic mix, and then compares the inventory on both a delivered feedstock and delivered electricity basis to a similar domestic mix of coal. The results show that average coal, across a wide range of variability, and compared across different assumptions of climate impact timing, has lower greenhouse gas emissions than domestically produced natural gas when compared as a delivered energy feedstock—over 50 percent less than natural gas per unit of energy.

However, the conclusion that coal is the cleaner fuel flips once the fuels are converted to electricity in power plants with different efficiencies—53 percent for natural gas versus 35 percent for coal. Natural gas-fired electricity has a 42 percent to 53 percent lower climate impact than coal-fired electricity. Even when fired on 100 percent unconventional natural gas, from tight sands, shale and coal beds, and compared on a 20-year GWP, natural gas-fired electricity has 39 percent lower greenhouse gases than coal. This shifting conclusion based on a change in the basis of comparison highlights the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases. There are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —70 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 17 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

The conclusions drawn from this inventory and the associated analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

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Appendix A: Data and Calculations for Greenhouse Gas Inventory

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The energy and material flows tracked by NETL's life cycle analysis (LCA) method in support of this study are used to quantify emissions of greenhouse gases (CO_2, CH_4, and N_2O, SF_6) that would result from natural gas extraction and transport, and from coal extraction and transport. The methods for calculating these flows for the raw material acquisition (RMA) and raw material transport (RMT) of natural gas and coal are provided below.

Some common engineering conversions used in this study are:

- 1 tonne = 1,000 kg
- 1 kg = 2.205 lb
- 1 m^3 = 35.3 cf
- Natural Gas Density: 1 cf of natural gas = 0.042 lb natural gas
- Natural Gas Energy Content: 1,027 Btu/cf natural gas
- The molar ratio of CO_2 to carbon is 44/12

A.1 Raw Material Acquisition: Natural Gas

In this analysis, the boundary of the RMA for natural gas begins with the extraction of natural gas from nature and ends with processed natural gas ready for pipeline delivery. Key activities in the RMA of natural gas are as follows:

- Well construction and installation
- Natural gas sweetening (acid gas removal)
- Natural gas dehydration
- Natural gas venting and flaring
- Natural gas compression
- Well decommissioning

The data sources and assumptions for calculating the greenhouse gas (GHG) emissions from each RMA activity are provided below. In most cases, the methane emissions are calculated by using standard engineering calculations around key gas field equipment, followed by the application of the Environmental Protection Agency (EPA) AP-42 emission factors as necessary.

Well Construction and Installation

NETL's LCA model of natural gas extraction includes the construction and installation activities for natural gas wells. Construction is defined as the cradle-to-gate burdens of key materials that embody key equipment and structures. Installation is defined as the activity of preparing a site, erecting buildings or other structures, and putting equipment in place.

The construction of natural gas wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. In the case of offshore extraction, a large platform is also required. A well is lined with a carbon steel casing that is held in place with concrete. A typical casing has an inner diameter of 8.6 inches, is 0.75 inches thick, and weighs 24 pounds per foot (NaturalGas.org, 2004). The weight of concrete used by the well walls is assumed to be equal to the weight of the steel casing. The total length of a natural gas well is variable, based on the natural gas extraction profile under consideration. The well lengths considered in this study are as follows: conventional onshore: 1,990 m; conventional offshore: 2,660 m; conventional onshore associated: 1,500 m; shale gas: 3,980 m; coal bed methane: 3,980 m; and tight gas: 2,525 m. The total weight of materials for the construction of a well bore is estimated by factoring the total well length by the linear weight of carbon steel and concrete.

The installation of natural gas wells includes the drilling of the well, followed by the installation of the well casing. Horizontal drilling is used for unconventional natural gas reserves where hydrocarbons are dispersed throughout a matrix of shale or coal. An advanced drilling rig has a drilling speed of 17.8 meters per hour, which translates to the drilling of a 7,000 foot well in approximately 10 days (NaturalGas.org, 2004). A typical diesel engine used for oil and gas exploration has a power of 700 horsepower and a heat rate of 7,000 Btu/hp-hr (EPA, 1995). The methane emissions from well installation is the product of the following three variables: heat rate of drilling engine (7,000 Btu/hp-hr), methane emission factor (EPA, 1995) for diesel combustion in stationary industrial engines (6.35E-05 lb/hp-hr), and the total drilling time (in hours).

The daily production rate of a natural gas well is an important factor in apportioning one-time construction activities or intermittent operations to a unit of natural gas production. Typical production rates vary considerably based on well type. Production rates also vary based on well specific factors, such as the age of the natural gas well. For instance, the average daily production rate for new, horizontal shale gas wells in the Barnett Shale region is as high as 2.5 million standard cubic feet (MMcf) per day, but declines at a rapid rate (Hayden & Pursell, 2005). The observed production rates in the Barnett Shale region decline 55 percent during the first year, 25 percent during the second year, 15 percent during the third year, and 10 percent each following year (Hayden & Pursell, 2005). The production rates for each type of natural gas well are shown in **Table A-12**. These production rates include the average production of natural gas wells in 2009 (the basis year of this analysis), as marginal production rates. Marginal production rates exclude poorly performing, mature wells that will likely be removed from service within a couple of years.

The construction and material requirements are apportioned to one kilogram of natural gas product by dividing them by the lifetime production of the well. The natural gas wells considered in this study are presumed to produce natural gas at the rates discussed above, with a lifetime of 30 years. Thus, construction and material requirements, and associated GHG emissions, are apportioned over the lifetime production rate specific to each type of natural gas well, based on average well production rates.

Natural Gas Sweetening (Acid Gas Removal)

Raw natural gas contains varying levels of hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas and causes fouling when combusted in equipment. The removal of H_2S from natural gas is known as sweetening. Amine-based processes are the predominant technologies for the sweetening of natural gas.

The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass is modeled in this analysis. This H_2S concentration is based on raw gas composition data compiled by the Gas Processors Association (Foss, 2004).

The energy consumed by the amine reboiler accounts for the majority of energy consumed by the sweetening process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. Approximately 0.30 moles of H_2S are removed per 1 mole of circulated amine solution (Polasek, 2006), the reboiler duty is approximately 1,000 Btu per gallon of amine (Arnold, 1999), and the reboiler has a thermal efficiency of 92 percent. The molar mass of amine solution is assumed to be 83 g/mole, which is estimated by averaging the molar mass of monoethanolamine (61 g/mole) and diethanolamine (105 g/mole). The density of the amine is assumed to be 8 lb/gal (3.62 kg/gal). The calculation of energy input per kilogram of natural gas product is shown in **Equation 1**.

$$\frac{0.005\ kg\ H_2S}{kg\ NG\ product} * \frac{1\ kg\ mol\ \ H_2S}{34\ kg\ H_2S} * \frac{1\ kg\ mol\ amine}{0.30 kg\ mol\ H_2S} * \frac{83\ kg\ amine}{kg\ mol\ amine} * \frac{1\ gal\ amine}{3.62\ kg\ amine} * \frac{1{,}000\ Btu\ reboiler\ duty}{gal\ amine} * \frac{1\ Btu\ energy\ input}{0.92\ Btu\ reboiler\ duty} = \frac{12.2\ Btu}{kg\ NG\ product} = \frac{26.9\ Btu}{lb\ NG\ product} \quad \textbf{(Equation 1)}$$

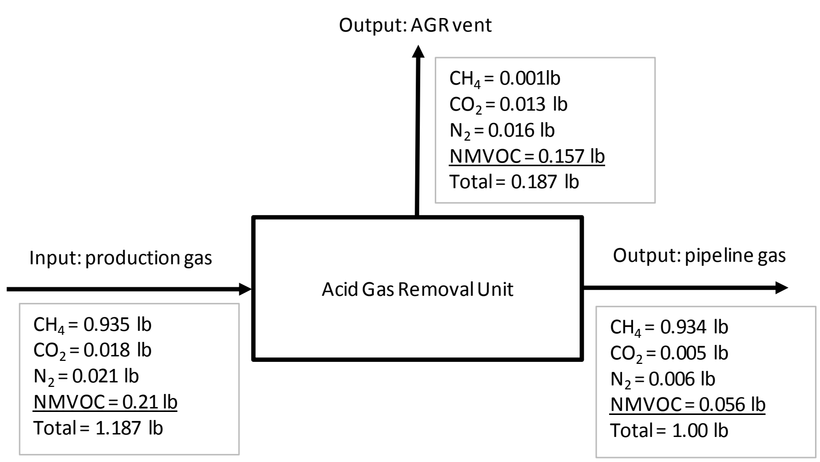
The amine reboiler combusts natural gas to generate heat for amine regeneration. This analysis applies EPA emission factors for industrial boilers (EPA, 1995) to the energy consumption rate discussed in the above paragraph in order to estimate the combustion emissions from amine reboilers.

The sweetening of natural gas is also a source of vented methane emissions. In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb per natural gas sweetened (API, 2009). The calculation of methane released by amine reboiler venting is shown in **Equation 2**.

$$\frac{0.0185\ tonne\ CH_4}{10^6\ cf\ NG} * \frac{1{,}000\ kg}{tonne} * \frac{2.205\ lb}{kg} * \frac{1 cf}{0.042\ lb} = \frac{9.71 \times 10^{-4}\ lb\ CH_4}{lb\ NG} \quad \textbf{(Equation 2)}$$

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. Most of this CO_2 is absorbed by the amine solution during the sweetening of natural gas and is ultimately released to the atmosphere when the amine is regenerated. This analysis calculates the mass of naturally-occurring CO_2 emissions from the acid gas recovery (AGR) unit by balancing the composition of production gas (natural gas that has been extracted but has not undergone significant processing) and pipeline-quality gas. Production gas contains 1.52 mass percent CO_2 and pipeline-quality natural gas contains 0.47 mass percent CO_2. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas. The key constraints of this mass balance are the different compositions of input gas (production gas) and output gas (pipeline-quality gas) and the methane venting rate from amine regeneration. The mass balance around the AGR unit is illustrated by **Figure A-1.**

Figure A-1: Mass Balance for Acid Gas Removal



As shown by the mass balance around the AGR unit, the majority (84 percent by mass) of the AGR vent stream is NMVOC. At this concentration, NMVOCs are a high-value energy product. Thus, from an LCA perspective, NMVOCs are a valuable co-product of the AGR process. Co-product allocation is used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

In this analysis, the relative energy contents of the natural gas and NMVOC outputs from the AGR process are used as the basis for co-product allocation. The heating value of pipeline-quality natural gas is 24,452 Btu/lb (which is calculated from the default study value of 1,027 Btu/cf). The heating value of NMVOCs is 21,025 Btu/lb, which is calculated from the composition of the vent stream from the AGR unit and the heating values of each NMVOC component (The Engineering Toolbox, 2011); the calculation of the heating value of NMVOC is shown in **Table A-1**. As shown by the mass balance (**Figure A-1**), 0.157 lbs of NMVOC are produced for every lb of natural gas produced. When these mass flows are converted to an energy basis using the above heating values, 88.1 percent of the product leaving the AGR process is natural gas and 11.9 percent is NMVOCs. Thus, the natural gas model allocates 88.1 percent of the energy requirements and environmental emissions of acid gas removal to the natural gas product.

Table A-1: Heating Value of NMVOC Co-Product from AGR Process

NMVOC Component	Percent Mass	Heating Value (Btu/lb)
CH_4	0%	23,811
Ethane	44.1%	20,525
Propane	26.7%	21,564
Iso-Butane	5.9%	21,640
n-Butane	10.4%	21,640
iso-Pentane	3.0%	20,908
n-Pentane	3.9%	20,908
Hexanes	3.0%	20,526
Heptanes Plus	2.9%	21,000
Other (N_2 and CO_2)	0%	0
	Composite Heating Value	21,025

The following table shows the energy consumption and GHG emissions for acid gas removal. These energy and emission factors do not account for the co-product allocation between natural gas and NMVOCs. The co-product allocation between natural gas and NMVOC is performed within the modeling software (GaBi).

For **Table A-2**, the energy used for acid gas removal is based on a 0.005 kg H_2S per of raw natural gas, a molar loading of 0.30 mol H2S per mole of amine solution, and a reboiler duty of 1,000 Btu/gal of regenerated amine, and a reboiler efficiency of 92 percent. The CH_4 venting factor assumes that the reboiler vent is not flared.

Table A-2: Acid Gas Removal (Sweetening)

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	26.9	Btu/lb NG product	calculated
Reboiler fuel	2.26E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2 (combustion)	6.47E-04	lb CO_2/lb NG product	calculated
CO_2 (vented)	0.013	lb CO_2/lb NG product	calculated
N_2O	3.54E-06	lb N_2O/lb NG product	calculated
CH_4 (combustion)	1.27E-05	lb CH_4/lb NG product	calculated
CH_4 (vented)	9.71E-04	lb CH_4/lb NG product	API 2009
NMVOC (vented)	0.157	lb NMVOC/lb NG product	calculated

Natural Gas Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

The fuel requirements of dehydration are a function of the reboiler duty. Due to the heat integration of the absorber and stripper streams, the reboiler, which is heated by natural gas combustion, is the only equipment in the dehydration system that consumes fuel. The reboiler duty (the heat requirements for the reboiler) is a function of the flow rate of glycol solution, which, in turn, is a function of the difference in water content between raw and dehydrated natural gas. The typical water content for untreated natural gas is 49 lbs/MMcf. In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs/MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is 3 gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gal (EPA, 2006). By factoring the change in water content, the glycol flow rate, and boiler heat requirements, the energy requirements for dehydration are 152,000 Btu/MMcf of dehydrated natural gas (as shown by **Equation 3** and **Equation 4** below). Assuming that the reboiler is fueled by natural gas, this translates to 1.48E-04 lb of natural gas combusted per lb of dehydrated natural gas (as shown by the equations below). The emission factor for the combustion of natural gas in boiler equipment produces 2.3 lb CH_4/million cf natural gas (API, 2009). After converting to common units, the above fuel consumption rate and methane emission factor translate to 8.09E-09 lb CH_4/lb NG treated.

$$\frac{3.00\ gal\ glycol}{lb\ water} * \frac{1{,}124\ Btu}{gal\ glycol} * \frac{(49-4)\ lb\ water}{MMCF\ NG} = \frac{152{,}000\ Btu}{MMcf\ NG} \qquad \textbf{(Equation 3)}$$

$$\frac{152{,}000\ Btu}{MMcf\ NG} * \frac{MMcf\ NG}{10^6 cf\ NG} * \frac{1\ cf\ NG}{1027\ Btu} = \frac{1.48\times10^{-4}\ lb\ NG\ fuel}{lb\ NG\ product} \quad \textbf{(Equation 4)}$$

In addition to absorbing water, the glycol solution also absorbs methane from the natural gas stream. This methane is lost to evaporation during the regeneration of glycol in the stripper column. Flash separators are used to capture most of methane emissions from glycol strippers; nonetheless, small amounts of methane are vented from dehydrators. The emission of methane from glycol dehydration is based on emission factors developed by the Gas Research Institute (API, 2009). Based on this emission factor, 8.06E-06 lb of methane is released for every pound of natural gas that is dehydrated.

For **Table A-3**, the energy used for dehydration is based on 3 gallons of glycol per pound of water removed, a reboiler duty of 1,124 Btu per gallon of glycol regenerated, and 45 pounds of water removed per MMcf of natural gas produced. The methane venting factor assumes that no flash separator is used to control venting emissions.

Table A-3: Natural Gas Dehydration

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	1.52E-01	Btu/cf NG product	API 2009
Reboiler fuel	1.48E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2	4.24E-04	lb CO_2/lb NG product	calculated
N_2O	2.26E-09	lb N_2O/lb NG product	calculated
CH_4 (combustion)	8.10E-09	lb CH_4/lb NG product	calculated
CH_4 (venting)	8.06E-06	lb CH_4/lb NG product	API 2009

Natural Gas Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring include carbon dioxide, methane, and nitrous oxide. The flaring emission factors published by the American Petroleum Institute (API, 2009) are based on the following recommendations by the Intergovernmental Panel on Climate Change (IPCC):

- If measured data are not available, assume flaring has a 98 percent destruction efficiency. Destruction efficiency is a measure of how much carbon in the flared gas is converted to CO_2 (API, 2009).
- The CO_2 emissions from flaring are the product the destruction efficiency, carbon content of the flared gas, the molar ratio of CO_2 to carbon (44/12). Methane is 75 percent carbon by mass, and the other hydrocarbons in natural gas are approximately 81 percent carbon by mass

(Foss, 2004); the composite carbon content of natural gas is calculated by factoring these carbon compositions with the natural gas composition.

- Methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2 (API, 2009).
- N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.8 percent CH_4, 1.5 percent CO_2, 1.78 percent nitrogen, and 17.9 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). The mass composition of pipeline quality natural gas is 93.4 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.6 percent NMVOCs. The composition of production natural gas to model flaring during natural gas extraction, and the composition of pipeline quality natural gas is used to model flaring at the natural gas processing plant. The above method for estimating flaring emissions was applied to these gas compositions to develop flaring emission factors for production and pipeline natural gas. The following table summarizes the mass composition and flaring emissions for these two gas compositions.

Table A-4: Natural Gas Flaring

Emission	Production NG	Pipeline NG	Units	Reference
Natural Gas Composition				
CH_4	78.8%	93.4%	% mass	(EPA, 2011a)
CO_2	1.52%	0.47%	% mass	(EPA, 2011a)
Nitrogen	1.78%	0.55%	% mass	(EPA, 2011a)
NMVOC	17.90%	5.57%	% mass	(EPA, 2011a)
Flaring Emissions				
CO_2	2.67	2.69	lb CO_2/lb flared NG	API, 2009
N_2O	8.95E-05	2.79E-05	lb N_2O/lb flared NG	API, 2009
CH_4	1.53E-02	1.81E-02	lb CH_4/lb flared NG	API, 2009

The venting rate of natural gas is necessary to apply the above emission factors to a unit of natural gas production. Venting rates are highly variable and depend more on the production practices and condition of equipment at an extraction site that the type of natural gas reservoir. Thus, venting rates have been parameterized in the model to allow uncertainty analysis.

Recent data indicate that only 51 percent of vented natural gas from conventional natural gas extraction operations is flared and the remaining 49 percent is released to the atmosphere (EPA, 2011a). The flaring rate is even lower for unconventional wells, which flare 15 percent of vented natural gas (EPA, 2011a). The flaring rate at natural gas processing plants is assumed to be 100 percent.

Venting from Well Completion

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a). Barnett Shale and tight gas wells are high pressure wells, and thus have higher completion venting than coal bed methane and conventional wells (EPA, 2011a).

When modeling tight gas, adjustments were made to EPA's emission factors for well completions and workovers. EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emissions are representative of high-pressure, tight gas wells in the San Juan and Piceance basins, which are horizontal wells that were completed using hydraulic fracturing and have an estimated ultimate recovery of 3 Bcf. A survey of tight gas production in the U.S. determined that an estimated ultimate recovery of 1.2 Bcf is more representative of U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. An emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells is used.

Tight gas emissions are not the only emission factor adjusted for the model. While coal bed methane (CBM) wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have relatively low emission rates from completions and workovers. The CBM emission factor used for the completion and workover of CBM wells is 49.57 Mcf CH_4 (EPA, 2011a). This is much lower than the completion and workover emission factor that EPA recommends for unconventional wells (9,175 Mcf CH_4).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) the methane emissions from conventional well completions are 1,538 lb/completion (698 kg/completion). For unconventional wells the venting rates are 386,000 lb/completion (175,000 kg/completion) for Barnett Shale, 2,090 lb/completion (946 kg/completion) for coal bed methane, and 154,000 lb/completion (70,064 kg/completion) for tight gas (EPA, 2011a).

Venting from Well Workovers

The methane emissions from the workover of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 2.454 Mcf/workover and unconventional wells produce 9,175 Mcf/workover. (Note that the workover emission factor for unconventional wells is the same as the completion emission factor for unconventional wells.) This analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) and the conversion factor of 2.205 lb/kg, the methane emissions from well workovers are 103 lb/workover (46.7 kg/workover) for conventional wells. The workover venting rates for unconventional wells are assumed to be equal to their completion venting rates (EPA, 2011a).

Unlike well completions, well workovers occur more than one time during the life of a well. The frequency of well workovers was calculated using EPA's accounting of the total number of natural gas wells in the U.S. and the total number of workovers performed per year (all data representative of 2007). For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

Venting from Liquid Unloading

Liquid unloading is necessary for conventional gas wells. It is not necessary for unconventional wells or associated gas wells.

The methane emissions from the unloading of liquid from conventional wells are based on emission factors developed by EPA. In 2007, conventional wells produced 223 Bcf/year (EPA, 2011a), which is 4.25 million metric tons per year using a natural gas density of 0.042 lb/cf. There were approximately 389,000 unconventional wells in 2007. When the annual emissions are divided by the total number of wells, the resulting emission factor is 10.9 metric tons per well-year.

Liquid unloading is a routine operation for conventional gas wells. The frequency of liquid unloading was calculated using EPA's assessment of two producers and the unloading activities for their wells (EPA, 2011a). From this sampling, EPA calculated that there are 31 liquid unloading episodes per well-year (EPA, 2011a).

When the emission factor for liquid unloading is divided by the average number of unloading episodes, the resulting methane emission factor is 776 lb/episode (352 kg/episode).

Venting from Wet Seal Degassing

The emission factor for wet seal degassing accounts for the natural gas lost during the regeneration of wet seal oil, which is used for centrifugal compressors. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010). According to EPA's sampling of these platforms, the emissions from wet seal oil degassing are 33.7 million m^3 of methane annually. These platforms produce 4.88 billion m^3 of natural gas annually. When the emission rate for this category is divided by the production rate, the resulting emission factor is 0.00690 m^3 of vented gas per m^3 of produced gas. Assuming the emissions have the same density as the produced gas, this emission factor is 0.00690 lb of natural gas/lb produced natural gas.

Fugitive Emissions from Pneumatic Devices

The extraction and processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction or processing site. Thus, this analysis assumes that the operation of pneumatic systems result in the emission of fugitive natural gas emissions.

Data for the fugitive emissions from pneumatic devices are based on EPA data for offshore wells, onshore wells, and gas processing plants (EPA, 2011a). EPA’s data is based on 2006 production (EPA, 2011a) and shows the methane emissions for specific wellhead and processing activities. This analysis translated EPA’s data to a basis of lb methane per lb of natural gas production by dividing the methane emission rate by the natural gas production rate. For example, the annual emissions from pneumatic devices used for offshore production are 7 MMcf of methane; when divided by the annual offshore production rate of 3,584,190 MMcf, this translates to an emission factor of 1.95E-06 lb of methane per lb of natural gas produced (this calculation assumes that the volumetric densities of methane and natural gas are the same). The fugitive emissions from pneumatic devices used by offshore wells, onshore wells, and natural gas processing plants are shown in the following table.

Table A-5: Fugitive Emissions from Pneumatic Devices

Location	MMcf/yr (EPA, 2011a)		Emission Factor
	CH_4 emission	NG Production	lb CH_4/lb NG
Onshore	52,421	19,950,828	2.63E-03
Offshore	7.0	3,584,190	1.95E-06
Processing	93	14,682,188	6.33E-06

Other Point Source and Fugitive Emissions

The emissions described above account for natural gas emissions from specific processes, including the episodic releases of natural gas during well completion, workovers, and liquid unloading, as well as routine releases from wet seal degassing, AGR, and dehydration. Natural gas is also released by other extraction and processing equipment. To account for these other emissions, NETL's model includes two additional emission categories: other point source emissions and other fugitive emissions. Other point source emissions account for natural gas emissions that are not accounted for elsewhere in model and can be recovered for flaring. Other fugitive emissions include emissions that are not accounted for elsewhere in the model and cannot be recovered for flaring.

EPA's Background Technical Support Document - Petroleum and Natural Gas Industry (EPA, 2011a) was used for quantifying the other point source and fugitive emissions from natural gas extraction and processing. A three-step process was used to filter EPA's venting and flaring data so that it is consistent with the boundary assumptions of this analysis:

1. Emissions that are accounted for by NETL's existing natural gas unit processes were not included in the categories for other point source and fugitive emissions. For example, EPA provides emission rates for well construction, well completion, dehydration, and pneumatic devices. The emissions from these activities are accounted for elsewhere in NETL's model and thus, to avoid double counting, are not included in the emission factors for other point and fugitive emissions.
2. Emissions that fall within NETL's boundary definitions for natural gas processing were moved from the natural gas extraction category to the natural gas processing category.
3. The EPA data (EPA, 2011a) does not discern between point source and fugitive emissions, so emissions were assigned to the point source or fugitive emission categories based on another EPA reference that provides more details on point source and fugitive emissions (Bylin, et al., 2010).

Other Point Source and Fugitive Emissions from Onshore Extraction

The data for other point source and fugitive emissions from onshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from construction, dehydration, compressors, well completion, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Additionally, emissions from Kimray pumps, condensate tanks, and compressor blowdowns are re-categorized as natural gas *processing* emissions in NETL's model, and are thus not included in the emission factors for natural gas *extraction*. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from onshore gas extraction are 7.49E-05 lb CH_4/lb NG extracted and 1.02E-03 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-6**.

Table A-6: Other Point Source and Fugitive Emissions from Onshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Gas Wells	2,751	Construction		
Heaters	1,463		1,463	
Separators	4,718			4,718
Dehydrators	1,297	Dehydrator		
Meters/Piping	4,556			4,556
Small Reciprocating Compressor	2,926	Reciprocating Compressor		
Large Reciprocating Compressor	664	Reciprocating Compressor		
Large Reciprocating Stations	45	Reciprocating Compressor		
Pipeline Leaks	8,087			8,087
Vented and Combusted				
Completion Flaring	0	Well Completion V&F		
Well Drilling	96	Well Completion		
Coal Bed Methane	3,467	Well Completion		
Pneumatic Device Vents	52,421	Pneumatic Devices		
Chemical Injection Pumps	2,814			2,814
Kimray Pumps	11,572	In NG processing boundary		
Dehydrator Vents	3,608	Dehydrator V&F		
Condensate Tanks without Control Devices	1,225	In NG processing boundary		
Condensate Tanks with Control Devices	245	In NG processing boundary		
Gas Engines, Compressor Exhaust Vented	11,680	Gas Compressor		
Well Workovers				
Well Workovers, Gas Wells	47	Well Workovers		
Well Workovers, Well Clean Ups (Low Pressure Gas Wells)	9,008	Well Workovers		
Blowdowns				
Blowdowns, Vessel	31		31	
Blowdowns, Pipeline	129			129
Blowdowns, Compressors	113	In NG processing boundary		
Blowdowns, Compressor Starts	253	In NG processing boundary		
Upsets				
Pressure Relief Valves	29			29
Mishaps	70			70
Total Emissions	123,315		1,494	20,403
Total NG Extracted	19,950,828			
Emission Rate (lb CH_4/lb NG extracted)			**7.49E-05**	**1.02E-03**

Other Venting and Fugitive Emissions from Offshore Extraction

The data for other point source and fugitive emissions from offshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from drilling rigs, flares, centrifugal seals, glycol dehydrators, gas engines and turbines, and pneumatic pumps; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from offshore gas extraction are 3.90E-05 lb CH_4/lb NG extracted and 2.41E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-7.**

Table A-7: Other Point Source and Fugitive Emissions from Offshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Amine gas sweetening unit	0.2	AGR and CO_2 removal		
Boiler/heater/burner	0.8		0.80	
Diesel or gasoline engine	0.01		0.01	
Drilling Rig	3	Construction		
Flare	24	Venting and Flaring		
Centrifugal Seals	358	Centrifugal Compressor		
Connectors	0.8			0.80
Flanges	2.4			2.38
Open Ended Line	0.1			0.10
Other	44			44.0
Pump Fugitive	0.5			0.50
Valves	19			19.00
Glycol Dehydrator	25	Dehydrator		
Loading Operation	0.1			0.10
Separator	796			796
Mud Degassing	8.0		8.00	
Natural Gas Engines	191	Reciprocating compressor		
Natural Gas Turbines	3.0	Centrifugal compressor		
Pneumatic Pumps	7.0	Pneumatic Devices		
Pressure Level Controls	2.0			2.00
Storage Tanks	7.0		7.00	
Variable Exhaust Nozzle Exhaust Gas	124		124	
Total Emissions	1616		140	865
Total Processed NG	3,584,190			
Emission Rate (lb CH_4/lb NG extracted)			**3.90E-05**	**2.41E-04**

Other Venting and Fugitive Emissions from Natural Gas Processing

The data for other point source and fugitive emissions from natural gas processing are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from reciprocating compressors, centrifugal compressors, AGR units, dehydrators, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from natural gas processing are 3.68E-04 lb CH_4/lb NG extracted and 8.25E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-8**.

Table A-8: Other Point Source and Fugitive Emissions from NG Processing

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Plants	1,634		3,104	
Recip Compressors	17,351	Reciprocating Compressor		
Centrifugal Compressors	5,837	Centrifugal Compressor		
Vented and Combusted (Normal Operations)				
Compressor Exhaust, Gas Engines	6,913	Reciprocating Compressor		
Compressor Exhaust, Gas Turbines	195	Centrifugal Compressor		
AGR Vents	643	AGR and CO_2 removal		
Kimray Pumps (Glycol Pump for Dehydrator)	177			11,749
Dehydrator Vents	1,088	Dehydrator venting & flaring		
Pneumatic Devices	93	Pneumatic Device		
Routine Maintenance				
Blowdowns/Venting	2,299		2,299	366
Total Emissions	36,230		5,403	12,115
Total Production	14,682,188			
Emissions Rate (lb CH_4/lb NG processed)			**3.68E-04**	**8.25E-04**

Natural Gas Compression

Compressors are used to increase the gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. The inlet pressure depends on the pressure of the natural gas reservoir and pressure drop during gas processing and thus introduces uncertainty to the model. The outlet pressure of 800 psig is a standard pressure for pipeline transport of natural gas.

The energy required for compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas. This energy rate represents the required *output* of the compressor shaft; the *input* fuel requirements for compression vary according to compression technology. The two types of compressors used for natural gas operations are reciprocating compressors and centrifugal compressors. These two compressor types are discussed below.

Reciprocating compressors account for an estimated 75 percent of wellhead compression in the Barnett Shale gas play, and are estimated to accounted for all wellhead compression at conventional onshore, conventional onshore associated, and coal bed methane wells. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Houston Advanced Research Center, 2006). The average energy intensity of a gas-powered turbine is 8.74 Btu/hp-hr (Houston Advanced Research Center, 2006). Using a natural gas heating value of 1,027 Btu/cf (API, 2009), a natural gas density of 0.042 lb/cf (API, 2009), and converting to kilograms translates to 217 kg of natural gas per MWh of centrifugal, gas-powered turbine output. This fuel factor represents the mass of natural gas that is combusted per compressor energy output. The carbon dioxide emissions from a gas-powered, 4-stroke reciprocating compressor are 110 lb/MMBtu of fuel input. Similarly, the methane emissions from the same type of reciprocating compressor are 1.25 lb/MMBtu of fuel input (EPA, 1995); these methane emissions result from leaks in compressor rod packing systems and are based on measurements conducted by the EPA on a sample of 22 compressors (EPA, 1995).

The emissions for the operation of wellhead compressors are shown in **Table A-9** below.

Table A-9: Gas-Powered Reciprocating Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	1.25 lb/MMBtu fuel	5.37E-04 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	478 lb NG/MWh	217 kg NG/MWh	HARC 2006
Fuel input	3.54E-02 lb NG/lb NG	3.54E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.095 lb/lb NG	0.095 kg/kg NG	calculated
CH_4	1.08E-03 lb/lb NG	1.08E-03 kg/kg NG	calculated

Gas powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage centrifugal compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas.

Table A-10: Gas-Powered Centrifugal Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	8.60E-03 lb/MMBtu fuel	3.70E-06 kg/MJ fuel	EPA 1995
N_2O	3.00E-03 lb/MMBtu fuel	1.29E-06 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	443 lb NG/MWh	201 kg NG/MWh	API 2009
Fuel input	3.28E-02 lb NG/lb NG	3.28E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.088 lb/lb NG	0.088 kg/kg NG	calculated
CH_4	6.89E-06 lb/lb NG	6.89E-06 kg/kg NG	calculated
N_2O	2.40E-06 lb/lb NG	2.40E-06 kg/kg NG	calculated

Electrically-powered centrifugal compressors account for an estimated 25 percent of wellhead compression in the Barnett Shale gas play, but were not found to be utilized in substantial numbers outside of the Barnett Shale. If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a city.

An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine. The average power range of electrically-driven compressor in the U.S. natural gas transmission network is greater than 500 horsepower. This analysis assumes that compressors of this size have an efficiency of 95 percent (DOE, 1996). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output. The upstream emissions associated with the generation of electricity are modeled with the fuel mix of the Electric Reliability Council of Texas (ERCOT) grid, which is representative of electricity generation in Texas (the location of Barnett Shale). The air emissions from electricity generation are based on the 2005 fuel mix for the ERCOT region (Texas) and are modeled by NETL's LCA model for power generation. Electric compressors have negligible methane emissions because they do not require a fuel line for the combustion of product natural gas and incomplete combustion of natural gas is not an issue (EPA, 2011c). Electric compressors are also recommended by EPA’s Natural Gas STAR program as a strategy for reducing system emissions of methane (EPA, 2011c).

Table A-11: Electrically-Powered Centrifugal Compressor Operations

Air Emissions from Electricity Generation			
CO_2	1,784 lb/MWh	809 kg/MWh	calculated
N_2O	2.29E-02 lb/MWh	1.04E-02 kg/MWh	calculated
CH_4	2.36 lb/MWh	1.07 kg/MWh	calculated
SF_6	2.23E-09 lb/MWh	1.01E-09 kg/MWh	calculated
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb NG	1.63E-04 MWh/kg	GE 2005
Heat rate	1.053 MWh/MWh	1.053 MWh/MWh	API 2009
Electricity input	7.80E-05 MWh/lb NG	1.72E-04 MWh/kg NG	calculated
Air Emissions			
CO_2	0.139 lb/lb NG	0.139 kg/kg NG	calculated
N_2O	1.78E-06 lb/lb NG	1.78E-06 kg/kg NG	calculated
CH_4	1.84E-04 lb/lb NG	1.84E-04 kg/kg NG	calculated
SF_6	1.73E-13 lb/lb NG	1.73E-13 kg/kg NG	calculated

Well Decommissioning

This analysis assumes that the de-installation of a natural gas well incurs ten percent of the energy requirements and emissions as the original installation of the well.

Compilation of Natural Gas Processes

All energy and emissions data for the extraction of natural gas are described above. The compilation of these data into a model for natural gas extraction involves the connection of all unit processes into an interdependent network.

To model the extraction of natural gas from different sources (onshore, offshore, unconventional, etc.) it is necessary to tune each unit process within this network with a set of source-specific parameters. The assumptions used to adjust the unit processes into profiles of specific natural gas types are shown in **Table A-12**.

Table A-12: Natural Gas Modeling Parameters

Property	Units	Onshore	Associated	Offshore	Tight Sands	Barnett Shale	Coal Bed Methane
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
2009 Production Rate	Mcf/day	65.6	121	2,795	110	273	104
Marginal Production Rate	Mcf/day	592	398	6,165	110	273	76.2
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	Mcf/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	Mcf/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	Mcf/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.043	0.043	0.01	0.043	0.043	0.043
Natural Gas Processing Plant							
AGR and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%	100%	100%	100%	100%	100%
Methane Absorbed into Amine Solution	lb CH_4/Mcf	0.04	0.04	0.04	0.04	0.04	0.04
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/Mcf	0.56	0.56	0.56	0.56	0.56	0.56
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/Mcf	0.21	0.21	0.21	0.21	0.21	0.21
NMVOC Absorbed into Amine Solution	lb NMVOC/Mcf	6.59	6.59	6.59	6.59	6.59	6.59
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%	100%	100%	100%	100%	100%
Water Removed by Dehydrator Unit	lb H_2O/Mcf	0.045	0.045	0.045	0.045	0.045	0.045
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/Mcf	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Pneumatic Devices and Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%	100%	100%	100%	100%	100%
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.05	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.02	0.02	0.02	0.02	0.02	0.02
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.03	0.03	0.03	0.03	0.03	0.03
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Production Rates for Conventional Onshore Natural Gas Wells

The purpose of this discussion is to describe the data sources and calculations used to determine the typical production rate of conventional onshore natural gas wells. The population of conventional onshore wells is a lot more diverse that other types of natural gas wells, and thus it is necessary to distinguish between the large population of wells with low production rates and the relatively small population of wells with high production rates.

The Energy Information Administration (EIA) collects production data for oil and gas wells in the U.S. and organizes it according to production rates. The EIA data for total U.S. production is shown in **Table A-13**. The data in **Table A-13** are copied directly from EIA (EIA, 2010b) and show 22 production rate brackets. The lowest bracket includes wells that produce less than one barrel of oil equivalent (BOE) per day, and the highest bracket represents wells that produce more than 12,800 BOE per day. The EIA data have separate groups for oil wells and gas wells; from these data, we know that in 2009 the U.S. had 363,459 oil wells and 461,388 gas wells. These data also show the co-production of oil at gas wells as well as the average per well production rate within each production rate bracket.

The goal of this discussion is to focus on conventional onshore gas extraction. The data in **Table A-13** includes offshore production, and to develop a more accurate representation of onshore gas production, it is necessary to remove offshore data from the total U.S. profile. The EIA also has data for offshore production, as shown by **Table A-14**. By subtracting the offshore data from the total U.S. well profile, production data exclusive to onshore wells can be determined, as shown in **Table A-15**.

Table A-13: U.S. Total 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010b)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (MMbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (Bcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/Day)
0-1	127,734	35.1	15.4	0.9	0.4	4.8	0.1	91,005	19.7	73.4	0.3	2.4	0.7	0.0
1-2	45,649	12.6	21.8	1.3	1.4	9.5	0.6	45,034	9.8	131.1	0.5	8.3	1.3	0.1
2-4	47,803	13.2	45.3	2.8	2.7	22.3	1.3	60,930	13.2	358.3	1.5	16.6	3.6	0.2
4-6	27,625	7.6	43.6	2.7	4.4	29.4	3.0	43,009	9.3	428.4	1.8	28.0	4.4	0.3
6-8	21,816	6.0	48.3	2.9	6.2	36.7	4.7	32,564	7.1	457.8	1.9	39.4	4.5	0.4
8-10	15,482	4.3	42.9	2.6	7.7	40.0	7.2	24,829	5.4	451.1	1.9	50.8	4.3	0.5
10-12	12,642	3.5	43.8	2.7	9.7	33.5	7.4	18,967	4.1	420.5	1.8	62.1	4.1	0.6
12-15	11,801	3.2	50.3	3.1	11.9	37.3	8.8	21,718	4.7	591.1	2.5	76.2	5.7	0.7
15-20	13,895	3.8	75.1	4.6	15.2	60.8	12.3	23,974	5.2	841.3	3.5	98.5	7.7	0.9
20-25	8,157	2.2	56.6	3.4	19.6	46.2	16.1	16,539	3.6	744.2	3.1	126.5	7.5	1.3
25-30	6,276	1.7	52.3	3.2	23.7	46.5	21.1	11,638	2.5	644.9	2.7	156.7	5.1	1.2
30-40	7,207	2.0	75.3	4.6	30.0	69.0	27.5	16,083	3.5	1,122.3	4.7	197.4	9.5	1.7
40-50	3,684	1.0	49.0	3.0	39.1	42.1	33.5	9,959	2.2	895.6	3.7	255.6	7.1	2.0
50-100	7,934	2.2	159.7	9.7	59.4	171.4	63.7	22,546	4.9	3,156.6	13.2	402.7	22.4	2.9
100-200	3,070	0.8	119.1	7.3	118.3	115.9	115.1	13,444	2.9	3,520.4	14.7	782.4	30.8	6.8
200-400	1,469	0.4	109.9	6.7	233.9	122.3	260.3	5,528	1.2	2,572.2	10.7	1,545.1	22.3	13.4
400-800	663	0.2	92.3	5.6	447.9	128.5	623.6	2,038	0.4	1,708.3	7.1	3,007.9	22.2	39.0
800-1,600	264	0.1	77.8	4.7	900.8	114.4	1,325.0	816	0.2	1,342.4	5.6	6,039.3	25.0	112.6
1,600-3,200	145	0.0	86.8	5.3	1,770.4	121.8	2,485.6	460	0.1	1,633.2	6.8	11,907.5	35.8	261.0
3,200-6,400	66	0.0	88.1	5.4	3,950.0	92.9	4,167.6	247	0.1	1,913.3	8.0	22,917.6	46.1	552.0
6,400-12,800	47	0.0	112.4	6.8	7,428.9	132.1	8,729.2	51	0.0	725.3	3.0	46,468.5	9.9	635.0
> 12,800	30	0.0	176.5	10.7	18,162.2	136.8	14,083.1	9	0.0	227.5	0.9	84,081.9	3.3	1,204.3
Total	**363,459**	**100.0**	**1,642.3**	**100.0**	**12.9**	**1,614.4**	**12.7**	**461,388**	**100.0**	**23,959.1**	**100.0**	**148.5**	**283.2**	**1.8**

Table A-14: Federal Gulf 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010a)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (Mbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (MMcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (MMcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (Mbbl)	Oil Rate per Well (bbl/Day)
0-1	46	1.5	3.1	0.0	0.3	4.8	0.4	116	4.4	52.2	0.0	1.9	0.7	0.0
1-2	23	0.8	6.5	0.0	1.2	10.2	1.9	55	2.1	112.1	0.0	8.2	1.7	0.1
2-4	40	1.3	30.4	0.0	2.5	43.0	3.5	70	2.7	278.2	0.0	15.8	4.2	0.2
4-6	37	1.2	41.6	0.0	4.0	71.0	6.8	74	2.8	538.6	0.0	27.4	8.1	0.4
6-8	43	1.4	66.9	0.0	5.4	108.4	8.8	51	1.9	499.7	0.0	37.8	8.2	0.6
8-10	46	1.5	101.6	0.0	7.0	169.0	11.7	43	1.6	609.0	0.0	50.0	6.4	0.5
10-12	32	1.1	89.2	0.0	9.2	111.5	11.5	35	1.3	547.3	0.0	56.6	14.5	1.5
12-15	65	2.2	229.0	0.0	11.3	267.8	13.2	51	1.9	1,041.6	0.1	69.9	28.1	1.9
15-20	99	3.3	448.9	0.1	14.1	676.8	21.2	89	3.4	2,557.3	0.1	93.8	43.2	1.6
20-25	101	3.4	625.5	0.1	18.6	792.3	23.5	84	3.2	3,023.3	0.2	121.1	56.3	2.3
25-30	111	3.7	856.6	0.2	23.1	937.8	25.3	77	2.9	3,140.6	0.2	146.8	59.5	2.8
30-40	216	7.2	2,107.2	0.4	28.5	2,821.7	38.2	126	4.8	7,456.0	0.4	191.8	109.5	2.8
40-50	189	6.3	2,403.6	0.4	37.1	2,952.2	45.6	108	4.1	7,788.0	0.4	240.3	175.6	5.4
50-100	638	21.3	13,471.4	2.5	60.5	16,722.2	75.1	351	13.3	42,876.5	2.3	394.8	718.7	6.6
100-200	506	16.9	21,060.9	3.9	118.8	23,817.1	134.4	388	14.7	99,838.2	5.3	815.0	1,272.4	10.4
200-400	303	10.1	23,902.4	4.4	234.2	27,232.1	266.9	357	13.5	171,637.2	9.1	1,587.1	2,113.7	19.5
400-800	157	5.2	24,319.8	4.5	465.6	28,928.2	553.8	281	10.6	267,687.1	14.2	3,139.7	3,352.2	39.3
800-1,600	124	4.1	37,018.6	6.8	911.9	51,361.6	1,265.2	155	5.9	297,842.7	15.8	6,179.4	5,209.8	108.1
1,600-3,200	86	2.9	53,804.6	9.9	1,901.4	73,151.5	2,585.1	72	2.7	281,825.9	15.0	12,283.7	5,179.9	225.8
3,200-6,400	58	1.9	79,016.7	14.5	4,001.7	81,878.3	4,146.6	34	1.3	259,606.8	13.8	24,584.0	4,941.2	467.9
6,400-12,800	45	1.5	107,626.0	19.8	7,472.5	126,500.1	8,782.9	16	0.6	234,073.5	12.4	53,797.6	909.8	209.1
> 12,800	30	1.0	176,482.4	32.5	18,162.2	136,845.3	14,083.1	8	0.3	200,795.6	10.7	85,773.4	2,324.5	992.9
Total	**2,995**	**100.0**	**543,712.9**	**100.0**	**541.3**	**575,403.0**	**572.8**	**2,641**	**100.0**	**1,883,827.2**	**100.0**	**2,396.7**	**26,538.1**	**33.8**

Table A-15: U.S. 2009 Distribution of Onshore Gas Wells (EIA, 2010a, 2010b)

Prod. Rate Bracket (BOE/day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/day)	Gas Energy Equivalent (MMBtu/day)	Oil Energy Equivalent (MMBtu/day)	% of Energy from Gas	Adjusted Gas Rate per Well, (Mcf/Day)[1]
0-1	90,889	19.8%	73.4	0.3%	2.2	0.7	0.0	2.3	0.1	94.9%	2.3
1-2	44,979	9.8%	131.0	0.6%	8.0	1.3	0.1	8.2	0.5	94.7%	8.4
2-4	60,860	13.3%	358.0	1.6%	16.1	3.6	0.2	16.6	0.9	94.6%	17.0
4-6	42,935	9.4%	427.9	1.9%	27.3	4.4	0.3	28.0	1.6	94.5%	29.0
6-8	32,513	7.1%	457.3	2.1%	38.5	4.5	0.4	39.6	2.2	94.7%	41.0
8-10	24,786	5.4%	450.5	2.0%	49.8	4.3	0.5	51.1	2.8	94.9%	52.0
10-12	18,932	4.1%	420.0	1.9%	60.8	4.1	0.6	62.4	3.4	94.8%	64.0
12-15	21,667	4.7%	590.1	2.7%	74.6	5.7	0.7	76.6	4.2	94.9%	79.0
15-20	23,885	5.2%	838.7	3.8%	96.2	7.7	0.9	98.8	5.1	95.1%	101.0
20-25	16,455	3.6%	741.2	3.4%	123.0	7.4	1.2	127.0	7.0	94.6%	130.0
25-30	11,561	2.5%	641.8	2.9%	152.0	5.0	1.2	156.0	7.0	95.8%	159.0
30-40	15,957	3.5%	1,114.8	5.1%	191.0	9.4	1.6	197.0	9.0	95.5%	201.0
40-50	9,851	2.1%	887.8	4.0%	247.0	6.9	1.9	254.0	11.0	95.8%	258.0
50-100	22,195	4.8%	3,113.7	14.1%	384.0	21.7	2.7	395.0	16.0	96.2%	399.0
100-200	13,056	2.8%	3,420.6	15.5%	718.0	29.5	6.2	737.0	36.0	95.4%	753.0
200-400	5,171	1.1%	2,400.6	10.9%	1,272.0	20.2	10.7	1,306.0	62.0	95.5%	1,332.0
400-800	1,757	0.4%	1,440.6	6.5%	2,246.0	18.9	29.4	2,307.0	170.0	93.1%	2,412.0
800-1,600	661	0.1%	1,044.6	4.7%	4,330.0	19.8	82.0	4,446.0	476.0	90.3%	4,793.0
1,600-3,200	388	0.1%	1,351.4	6.1%	9,542.0	30.6	216.0	9,800.0	1,254.0	88.7%	10,763.0
3,200-6,400	213	0.0%	1,653.7	7.5%	21,271.0	41.2	529.0	21,845.0	3,071.0	87.7%	24,261.0
6,400-12,800	35	0.0%	491.2	2.2%	38,452.0	9.0	704.0	39,490.0	4,082.0	90.6%	42,427.0
> 12,800	1	0.0%	26.7	0.1%	73,163.0	1.0	2,673.0	75,138.0	15,501.0	82.9%	88,256.0
Total	**458,747**	**100.0%**	**22,075.4**	**100.0%**	**132.0**	**256.8**	**1.5**	**135.0**	**8.9**	**93.8%**	**140.0**

[1] Adjusted by energy-based co-product allocation

Co-product Allocation of Oil

The EIA data also shows that gas wells produce a small share of oil. On an energy basis, oil comprises approximately 3.8 to 17 percent of gas well production, depending on the production rate bracket. Using energy-based, co-product allocation, it is necessary to scale the production rates of the gas wells so they are representative of 100 percent gas production.

For example, a gas well that has daily production rates of 718 Mcf of natural gas and 6.2 barrels of oil has a total daily production of 773 MMBtu of energy. This energy equivalency is calculated using heating values of 1,027 Btu/cf for natural gas and 5.8 MMBtu/bbl for oil. If expressed solely on and energy-equivalent basis of natural gas, 773 MMBtu of energy is equal to 753 Mcf of natural gas. Thus, in this instance, accounting for the co-production of oil increases the nominal production rate of the gas well from 718 Mcf/day to 752 Mcf/day. Note that this nominal rate of 752 Mcf/day does not represent the actual gas produced by the well, but is an LCA accounting method that uses the relative energies of produced oil and natural gas to scale the gas production rate so it is representative of a well that produces only natural gas.

Selection of Representative Production Brackets

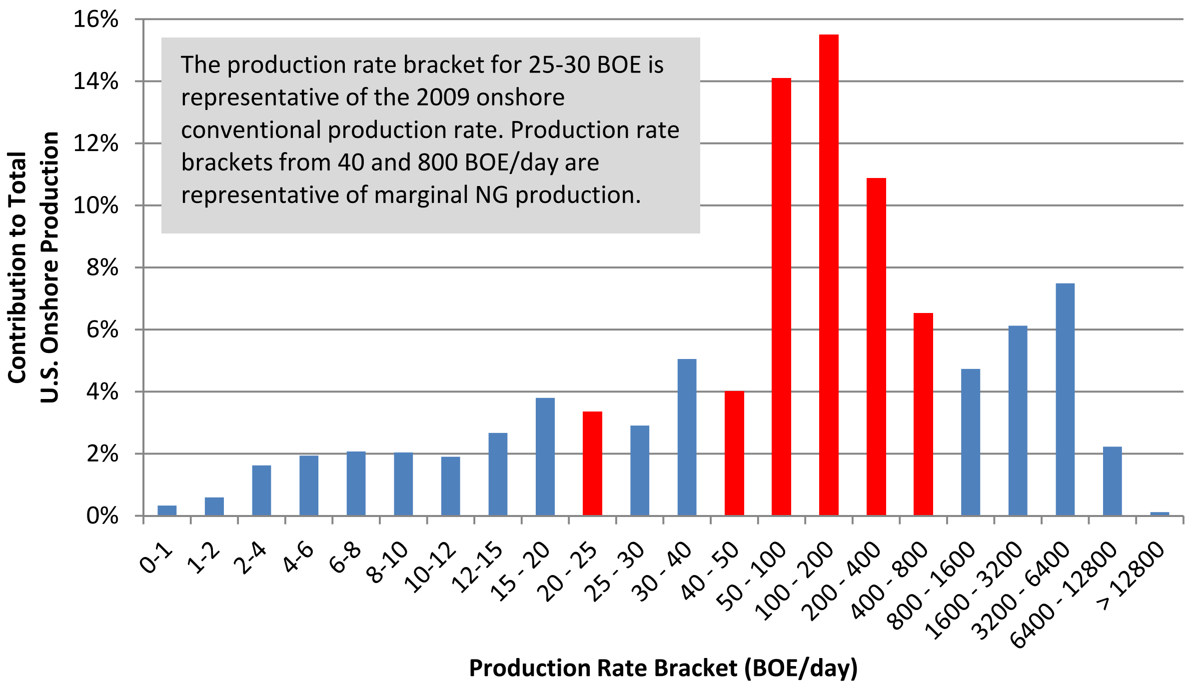
The production rates of onshore conventional natural gas wells vary widely and are a function of reservoir properties, extraction technology, and age. As shown by the EIA data, the production rates of onshore gas wells range from less than 1 BOE/day to more than 12,800 BOE/day. There are not enough data to determine the split between conventional and unconventional wells within each production rate bracket; however, the total production of each bracket and the production rates of unconventional wells can be used to determine the most likely production rates for onshore conventional natural gas. The distribution of gas wells by total gas produced is shown in **Figure A-2**

The production categories in **Table A-15** include a large population of wells in the lowest production rate bracket; 19.8 percent of U.S. onshore natural gas wells produce less than one BOE per day. Similarly, the production rate bracket for 1 - 2 BOE/day includes 9.8 percent of natural gas wells, the production rate bracket for 2 - 4 BOE/day includes 13.3 percent of natural gas wells, and the production rate bracket for 4 - 6 BOE/day includes 9.4 percent of natural gas wells. While these four production rate brackets account for 52 percent of the total count of natural gas wells, they account for only 4.5 percent of total natural gas production.

The average production rate for conventional onshore natural gas wells in 2009 was 66 Mcf per day. This production rate was calculated by dividing the amount of onshore conventional natural gas that was produced in 2009 by the total number of onshore conventional natural gas wells in 2009.

The marginal production rate for conventional onshore natural gas was calculated by selecting the most productive region of the production rate brackets. The production rate brackets that include 40 to 800 BOE/day represent 51 percent of total onshore natural gas production. The average production rate of this range of wells is 592 Mcf/day.

Figure A-2: Distribution of Onshore Natural Gas Wells



A.2 Raw Material Acquisition: Coal

Raw material extraction for coal incorporates extraction profiles for coal derived from the PRB, where sub-bituminous, low-rank coal extracted from thick coal seams (up to approximately 180 feet) via surface mines located in Montana and Wyoming, and coal derived from the Illinois No. 6 coal seam, where bituminous coal is extracted from approximately 2 to 15 foot seams via underground longwall and continuous mining. Each modeling approach is described below.

Powder River Basin Coal

The PRB coal-producing region consists of counties in two states – Big Horn, Custer, Powder River, Rosebud, and Treasure in Montana, and Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, and Weston in Wyoming (EIA, 2009). PRB coal is advantageous in comparison to bituminous coals in that it has lower ash and sulfur content. However, PRB coal also has a lower heating value than higher rank coals (Clyde Bergemann, 2005). In 2007, there were 17 surface mines extracting PRB coal, which produced over 479 million short tons (EIA, 2009).

PRB coal is modeled using modern mining methods in practice at the following mines: Peabody Energy's North Antelope-Rochelle mine (97.5 million short tons produced in 2008), Arch Coal, Inc.'s Black Thunder Mine (88.5 million short tons produced in 2008), Rio Tinto Energy America's Jacobs Ranch (42.1 million short tons produced in 2008), and Cordero Rojo Operation (40.0 million short tons produced in 2008). These four mines were the largest surface mines in the United States in 2008 according to the National Mining Association's 2008 Coal Producer Survey (National Mining Association, 2009).

Equipment and Mine Site

Much of the equipment utilized for surface coal mining in the PRB is very large. GHG emissions that result from the production of construction materials required for coal extraction were quantified for the following equipment, within the model: track loader (10 pieces at 26,373 kg each); rotary drill (3 pieces at 113,400 kg each); walking dragline (3 pieces at 7,146,468 kg each); electric mining shovel (10 pieces at 1,256,728 kg each); mining truck (11 pieces at 278,690 kg each); coal crusher (1 piece at 115,212 kg); conveyor (1 piece at 1,064,000 kg); and loading silo (6 pieces at 10,909,569 kg each).

Coal seams are located relatively close to the ground surface in the PRB such that large-scale surface mining is common. The coal seam ranges in thickness from 42 to 184 feet thick (EPA, 2004a). Before overburden drilling and cast blasting can be carried out, topsoil and unconsolidated overburden must be removed from the consolidated overburden that is to be blasted. These operations use both truck and shovel operations and bulldozing to move these materials to a nearby stockpile location so that they can be used in post-mining site reclamation. Estimates are made for topsoil/overburden operations based on requirements reported in the Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002) for a hypothetical western surface coal mine.

Overburden Blasting and Removal

Blast holes are drilled into overburden for subsequent ammonium nitrate and fuel oil packing and detonation using large rotary drills. Drills use electricity to drill 220-270 millimeter diameter holes through sandstone, siltstone, mudstone and carbonaceous shale that make up the overburden. Typically this overburden contains water, which controls particulate emission associated with drilling activities. For the purposes of this assessment it is assumed that drilling operations produce no direct emissions. Electricity requirements for drilling are taken from the U.S. DOE report Mining Industry for the Future: Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002).

Cast blasting is a blasting technique that was developed relatively recently, and has found broad application in large surface mines. Cast blasting comminutes (breaks into fragments/particles) overburden, and also moves an estimated 25-35 percent (modeled at 30 percent) of the blasted overburden to the target fill location (Mining Technology, 2007). The model assumes that blasting uses ammonium nitrate and fuel oil explosives with a powder factor[1] of 300 g per m^3 of overburden blasted (SME, 1990), and GHG emissions associated with explosive production and the blasting process are included in the model, based on EPA's AP-42 report (EPA, 1995).

Overburden removal is achieved primarily through dragline operations, with the remainder moved using large electric shovels. Dragline excavation systems are among the largest on-land machines, and utilize a large bucket suspended from a boom, where the bucket is scraped along the ground to fill the bucket. The bucket is then emptied at a nearby fill location. Electricity requirements for dragline operation combined with other on site operations, were estimated based on electricity usage at the North Antelope Rochelle Mine, to be approximately 971 kWh per 1000 tons of coal (Peabody, 2006). During this time dragline operation accounted for approximately 50% of the overburden energy.

[1] Powder factor refers to the mass of explosive needed to blast a given mass of material.

Coal Recovery

Following overburden removal, coal is extracted using truck and shovel-type operations. Because of the large scale of operations, large electric mining shovels (Bucyrus 495 High Performance Series) are assumed to be employed, with a bucket capacity of 120 tons, alongside 320-400 ton capacity mining trucks (Bucyrus International Inc., 2008).

The amount of coal that could be moved by a single shovel per year was determined by using data for the Black Thunder and Cordero Rojo coal mines (Mining Technology, 2007). A coal hauling distance of two miles is assumed, with a round-trip distance of four miles, based on evaluation of satellite imagery of mining operations. The extracted coal is ground and crushed to the necessary size for transportation. It is assumed that the coal does not require cleaning before leaving the mine site. The crushed coal is carried from the preparation facility to a loading silo by an overland conveyor belt. From the loading silo, the coal is loaded into railcars for transportation.

Coal Bed Methane Emissions

During coal acquisition, methane is released during both the coal extraction and post-mining coal preparation activities. While the PRB has relatively low specific methane content, the large thickness of the coal deposit (80 feet thick or more in many areas) has a large methane content per square foot of surface area. As a result the PRB has recently begun to be exploited on a large scale. Extraction of coal bed methane, prior to mining of the coal seam, results in a net reduction of the total amount of coal bed methane that is emitted to the atmosphere, since extracted methane is typically sold into the natural gas market, and eventually combusted.

For the purposes of this assessment, it is assumed that the coal seam in the area of active mining was previously drilled to extract methane. Based on recent data available from the EPA, coal bed methane emissions for surface mining, including the PRB, are expected to range from 8 to 98 standard cubic feet per ton (cf/ton) of produced coal, with a typical value of 51 cf/ton (EPA, 2011b).

Illinois No. 6 Coal

Illinois No. 6 coal is part of the Herrin Coal, and is a bituminous coal that is found in seams that typically range from about 2 to 15 feet in thickness, and is found in the southern and eastern regions of Illinois and surrounding areas. Illinois No. 6 coal is commonly extracted via underground mining techniques, including continuous mining and longwall mining. Illinois No. 6 coal seams may contain relatively high levels of mineral sediments or other materials, and therefore require coal cleaning (beneficiation) at the mine site. The following sections describe the unit processes modeled for Illinois No. 6 coal mining.

Equipment and Mine Site

Extraction of Illinois No. 6 coal requires several types of major equipment and mining components, in order to operate the coal mine. The following components were modeled for use during underground mining operations: site paving and concrete, conveyor belt, stacker/reclaimer, crusher, coal cleaning, silo, wastewater treatment, continuous miner, longwall mining systems (including shear head, roof supports, armored force conveyor, stage loader, and mobile belt tailpiece), and shuttle car systems with replacement. Overall, when considering materials requirements for the construction of these systems, the material inputs values shown in **Table A-16** were required for mine and mining system construction, on a per lb of coal output basis. GHG emissions associated with the production of these materials were incorporated into the model and accounted for as construction related emissions.

Table A-16: Construction Materials Required for Illinois No. 6 Coal Mining

Construction Material	Amount	Units
Cold-Rolled Steel	1.47E-05	lb/lb coal produced
Hot-dip Galvanized Steel	1.52E-06	lb/lb coal produced
Rubber	4.45E-07	lb/lb coal produced
Steel Plate	1.80E-04	lb/lb coal produced
Concrete	6.06E-05	lb/lb coal produced
Rebar	1.41E-06	lb/lb coal produced
Polyvinylchloride Pipe	1.30E-07	lb/lb coal produced
Steel, Stainless, 316	6.77E-08	lb/lb coal produced
Stainless Steel Cold Roll 431	6.77E-08	lb/lb coal produced
Cast Iron	3.38E-07	lb/lb coal produced
Copper Mix	8.11E-09	lb/lb coal produced
Asphalt	1.11E-03	lb/lb coal produced

Coal Mine Operations

Operations of the coal mine were based on operation of the Galatia Mine, which is operated by the American Coal Company and located in Saline County, Illinois. Sources reviewed in support of coal mine operations include Galatia Mine production rates, electricity usage, particulate emissions, methane emissions, wastewater discharge permit monitoring reports, and communications with Galatia Mine staff. When data from the Galatia Mine were not available, surrogate data were taken from other underground mines, as relevant.

Electricity is the main source of energy for coal mine operations. Electricity use for this model was estimated based on previous estimates made by EPA for electricity use for underground mining and coal cleaning at the Galatia Mine (EPA, 2008). The life cycle profile for electricity use is based on eGRID2007. The Emissions and Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes for electric power systems (EPA, 2010).

Although no Galatia Mine data were found that estimated the diesel fuel used during mining operations, it was assumed that some diesel would be used to operate trucks for moving materials, workers, and other secondary on-site operations. Therefore, diesel use was estimated for the Galatia Mine from 2002 U.S. Census data for bituminous coal underground mining operations and associated cleaning operations (U.S. Census Bureau, 2004). Emissions of GHGs were based on emissions associated with the use of diesel. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a couple years of commissioning of the mine for this study (EPA, 2004b).

Coal Bed Methane

During the acquisition of Illinois No. 6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Illinois No. 6 coal seams are not nearly as thick as PRB coals, and as a result are less commonly utilized as a resource for coal bed methane extraction. Instead, methane capture may be applied during the coal extraction process. Based on recent data available from the EPA, coal bed methane emissions for underground mining, including mining within the Illinois No. 6 coal seam, are expected to range from 360 to 500 cf/ton of produced coal, with a nominal value of 422 cf/ton (EPA, 2011b). It is assumed that no methane capture is applied for Illinois No. 6 coal.

A.3 Raw Material Transport: Natural Gas

The boundary of raw material transport begins with receipt of processed natural gas at the extraction site and ends with the delivery of natural gas to an energy conversion facility. Methane emissions from pipeline operations are a function of pipeline distance. This analysis uses a pipeline transport distance of 604 miles (971.4 km), which is the average distance for natural gas pipeline transmission in the U.S. The data sources and assumptions for calculating the greenhouse gas emissions from construction and operation of natural gas transmission pipelines are discussed below.

Pipeline Construction and Decommissioning

Carbon steel is the primary material used in the construction of natural gas pipelines. The mass of pipeline per unit length was determined using an online calculator (Steel Pipes & Tubes, 2009). The weight of valves and fittings were estimated at an additional 10 percent of the total pipeline weight. The pipeline was assumed to have a life of 30 years. The mass of pipeline construction per kilogram of natural gas was determined by dividing the total pipeline weight by the total natural gas flow through the pipeline for a 30-year period.

The decommissioning of a natural gas pipeline involves cleaning and capping activities. This analysis assumes that the decommissioning of a natural gas pipeline incurs 10 percent of the energy requirements and emissions as the original installation of the pipeline.

Pipeline Operations

The U.S. has an extensive natural gas pipeline network that connects natural gas supplies and markets. Compressor stations are necessary every 50 to 100 miles along the natural gas transmission pipelines in order to boost the pressure of the natural gas. Compressor stations consist of centrifugal and reciprocating compressors. Most natural gas compressors are powered by natural gas, but, when electricity is available, electrically-powered compressors are used.

A 2008 paper published by the Interstate Natural Gas Association of America provides data from its 2004 database, which shows that the U.S. pipeline transmission network has 5,400 reciprocating compressors and over 1,000 gas turbine compressors (Hedman, 2008). Further, based on written communication from El Paso Pipeline Group, approximately three percent of transmission compressors are electrically driven (El Paso Pipeline Group, 2011). El Paso Pipeline Group has the highest transmission capacity of all natural gas pipeline companies in the U.S., and it is thus assumed that the share of electrically-powered compressors in their fleet is representative of the entire natural gas transmission network. Based on written communication with El Paso Pipeline Group (El Paso Pipeline Group, 2011), the share of compressors on the U.S. natural gas pipeline transmission network is approximately 78 percent reciprocating compressors, 19 percent turbine-powered centrifugal compressors, and 3 percent electrically-powered compressors.

The use rate of natural gas for fuel in transmission compressors was calculated from the Federal Energy Regulatory Commission (FERC) Form 2 database, which is based on an annual survey of gas producers and pipeline companies (FERC, 2010). The 28 largest pipeline companies were pulled from the FERC Form 2 database. These 28 companies represent 81 percent of NG transmission in 2008. The FERC data for 81 percent of U.S. natural gas transmission is assumed to be a representative sample of the fuel use rate of the entire transmission network. This data shows that

0.96 percent of natural gas product is consumed as compressor fuel. This fuel use rate was converted to a basis of kg of natural gas consumed per kg of natural gas transported by multiplying it by the total natural gas delivered by the transmission network in 2008 (EIA, 2011) and dividing it by the annual tonne-km of pipeline transmission in the U.S. (Dennis, 2005). The total delivery of natural gas in 2008 was 21 Tcf, which is approximately 400 billion kg of natural gas. The annual transport rate for natural gas transmission was steady from 1995 through 2003, at approximately 380 billion tonne-km per year. More recent transportation data are not available, and thus this analysis assumes the same tonne-km rate for 2008 as shown from 1995 through 2003.

The air emissions from the combustion of natural gas by compressors are estimated by applying EPA emission factors to the natural gas consumption rate of the compressors (EPA, 1995). Specifically, the emission profile of gas-powered, centrifugal compressors is based on emission factors for gas turbines; the emission profile of gas-powered, reciprocating compressors is based on emission factors for 4-stroke, lean burn engines. For electrically-powered compressors, this analysis assumes that the indirect emissions are representative of the U.S. average fuel mix for electricity generation.

The average power of electrically-driven compressors for U.S. NG transmission is assumed to be the same as the average power of all compressors on the transmission network. An average compressor on the U.S. natural gas transmission network has a power rating of 14,055 horsepower (10.5 MW) and a throughput of 734 million cubic feet of natural gas per day (583,000 kg NG/hour) (EIA, 2007). Electrically-driven compressors have efficiencies of 95 percent (DOE, 1996; Hedman, 2008). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output.

In addition to air emissions from combustion processes, fugitive venting from pipeline equipment results in the methane emissions to air. The fugitive emission rate for natural gas pipeline operations is based on data published by the Bureau of Transportation Statistics (BTS) and EPA. The transport data for natural gas transmission is based on ton-mileage estimates by BTS, which calculates 253 billion ton-miles of natural gas transmission in 2003 (Dennis, 2005). The 2003 data are the most recent data point in the BTS reference, and thus EPA's inventory data for the years 2000 and 2005 were interpolated to arrive at a year 2003 value of 1,985 million kg of fugitive methane emissions per year (EPA, 2011b). Dividing the EPA emission by the transport requirements and converting to metric units gives 5.37E-06 kg/kg-km.

Calculation of Average Natural Gas Transmission Distance

The average pipeline distance for natural gas transport is determined by balancing national emission inventory (EPA, 2011b) and natural gas consumption data (EIA, 2011) with NETL’s unit process emission factor for fugitive methane emissions from pipeline operations. **Equation 5** shows the national inventory and consumption data on the left-hand side and NETL’s emission factor for fugitive methane on the right-hand side.

$$\frac{E_{methane}}{NG_{consumption}} = d * EF_{methane} \qquad \textbf{(Equation 5)}$$

Where,

$E_{methane}$ = Total pipeline fugitive methane emissions (default = 2,115E+06 kg CH_4/yr)
$NG_{consumption}$ = consumption of natural gas (default = 21.84 MMBtu/yr)
$EF_{methane}$ = Emission factor for fugitive methane (default =9.97E-05 kg CH_4/MMBtu-km)

The default value for total fugitive emissions of methane from pipeline transmission are based on the 2009 national inventory emissions for natural gas transmission and storage reported by EPA (EPA, 2011b). The value reported by EPA is 2,115 Gg CH_4/yr, which is equal to 2,115 million kg CH_4/yr.

The default value for annual natural gas consumption is based on annual EIA statistics for natural gas production and consumption (EIA, 2011). The volume of natural gas transported by pipeline is 21.26 Tcf/year. This value is the midpoint of the volume of processed natural gas injected to the pipeline transmission network and the volume of natural gas delivered to consumers. In 2009 the volume of natural gas injected to the natural gas transmission network by NG processing plants was 21.56 Tcf; this volume was calculated by subtracting the natural gas consumption at the extraction and processing sites (1.28 Tcf) from total annual consumption (22.84 Tcf) (EIA, 2011). In 2009 the volume of natural gas delivered to consumers was 20.97 Tcf (EIA, 2011). The average volume of natural gas transmission was converted to an energy basis using an energy density of 1,027 Btu/cf; 21.26 Tcf/year is equivalent to 21.84 E+09 MMBtu. Converting to an energy basis (using a density of 0.042 lbs/cf and energy content of 1,027 Btu/cf) gives 21.84 billion MMBtu.

For **Equation 5** it is necessary to convert the emission factor for fugitive emissions from pipeline operations (calculated above) to an energy basis so that it can be factored with the annual consumption data for natural gas. The emission factor used by the pipeline unit process is 5.37E-06 kg/kg-km. Converting to an energy basis (using the conversion factors of 0.042 lb/cf NG and 1,027 Btu/cf) results in an emission factor of 9.97E-05 kg CH_4/MMBtu-km.

The unknown *d* in **Equation 5** is the distance (km) that reconciles NETL's unit process with the national level data. Solving for *d* gives the following equation:

$$d = \frac{E_{methane}}{NG_{consumption} * EF_{methane}} \qquad \textbf{(Equation 6)}$$

Applying the default values to **Equation 6** gives a distance of 971 km (604 miles), as shown in **Equation 7**.

$$d = \frac{2{,}115\times10^{6} kg\ CH_4/yr}{(21.84\times10^{9} MMBtu/yr)(9.97\times10^{-5} kgCH_4/MMBtu\ km)} = 971\ km \qquad \textbf{(Equation 7)}$$

The pipeline transport of natural gas results in losses of natural gas product to two activities: (1) fugitive emissions and (2) natural gas used as fuel in pipeline compressors. Based on the data and assumptions of this unit process, the transmission of natural gas a distance of 971 km results in a 1.45 percent loss of natural gas product (1.0148 kg of natural gas are injected into the pipeline to deliver 1.0 kg of natural gas to the consumer). The annual data for natural gas production and consumption (EIA, 2011) show a 2.81 percent loss of natural gas for transmission and distribution (natural gas processing plants produce 21.56 Tcf of natural gas and 20.97 Tcf of natural gas are delivered to consumers). The 2.81 percentage loss factor includes pipeline *distribution* in addition to pipeline transmission, and thus it is expected for the transmission losses (1.45 percent) to be lower than the transmission and distribution loss (2.81 percent).

The default values for key variables for NETL's model of natural gas pipeline transmission are shown in the **Table A-17**.

Table A-17: Natural Gas Transport to Large End User

Natural Gas Emissions and Transmission Infrastructure	Units	Value
Pipeline Transport Distance (national average)	Miles	604
Distance Between Compressor Stations	Miles	75
Compression, Gas-powered, Reciprocating Engine	Percent	78%
Compression, Gas-powered, Centrifugal Engine	Percent	19%
Compression, Electrical, Centrifugal Engine	Percent	3%

A.4 Raw Material Transport: Coal

Train transport was modeled for the transport of both PRB and Illinois No. 6 coal from mining sites to energy conversion facilities. Mined coal is presumed to be transported by rail from PRB and Illinois No. 6 coal mine sources, in support of electricity production. Coal is assumed to be transported via unit train, where a unit train is defined as one locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400 horsepower diesel engine (General Electric, 2008) and each car has a 100-ton coal capacity (NETL, 2007).

GHG emissions for train transport are evaluated based on typical diesel combustion emissions for a locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions; loss during loading at the mine is assumed to be included in the coal reject rate and no loss is assumed during unloading. It is assumed that the majority of the railway connecting the coal mine and the energy conversion facility is existing infrastructure. An assumed 25-mile rail spur was constructed between the energy conversion facility and the primary railway.

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Appendix B:
Inventory Results in Alternate Units

Table B-1: Upstream Greenhouse Gas Inventory Results for Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Gas	CO_2	5.93E+00	1.05E+00	6.98E+00	2.69E+00	4.76E-01	3.16E+00	2.55E+00	4.51E-04	3.00E-03	1.22E+01	2.16E+00	1.43E+01
	N_2O	1.85E-04	2.02E-05	2.05E-04	8.39E-05	9.17E-06	9.31E-05	7.95E-05	8.69E-06	8.82E-05	3.80E-04	4.15E-05	4.22E-04
	CH_4	6.42E-01	2.14E-01	8.56E-01	2.91E-01	9.69E-02	3.88E-01	2.76E-01	9.18E-02	3.68E-01	1.32E+00	4.39E-01	1.76E+00
	CO_2e (20-year)	52.2	16.4	68.6	23.7	7.5	31.1	22.4	7.1	29.5	107.2	33.8	141.0
	CO_2e (100-year)	22.0	6.4	28.4	10.0	2.9	12.9	9.5	2.7	12.2	45.3	13.1	58.4
	CO_2e (500-year)	10.8	2.7	13.5	4.9	1.2	6.1	4.7	1.2	5.8	22.3	5.5	27.8
Conv. Gas	CO_2	6.34E+00	1.05E+00	7.38E+00	2.87E+00	4.76E-01	3.35E+00	2.72E+00	4.51E-01	3.17E+00	1.30E+01	2.16E+00	1.52E+01
	N_2O	2.14E-04	2.02E-05	2.35E-04	9.72E-05	9.17E-06	1.06E-04	9.22E-05	8.69E-06	1.01E-04	4.40E-04	4.15E-05	4.82E-04
	CH_4	5.29E-01	2.14E-01	7.43E-01	2.40E-01	9.69E-02	3.37E-01	2.28E-01	9.18E-02	3.19E-01	1.09E+00	4.39E-01	1.53E+00
	CO_2e (20-year)	44.5	16.4	60.9	20.2	7.5	27.6	19.1	7.1	26.2	91.4	33.8	125.2
	CO_2e (100-year)	19.6	6.4	26.0	8.9	2.9	11.8	8.4	2.7	11.2	40.3	13.1	53.5
	CO_2e (500-year)	10.4	2.7	13.1	4.7	1.2	5.9	4.5	1.2	5.6	21.3	5.5	26.8
UnConv. Gas	CO_2	5.60E+00	1.05E+00	6.65E+00	2.54E+00	4.76E-01	3.02E+00	2.41E+00	4.51E-01	2.86E+00	1.15E+01	2.16E+00	1.37E+01
	N_2O	1.62E-04	2.02E-05	1.82E-04	7.33E-05	9.17E-06	8.25E-05	6.95E-05	8.69E-06	7.82E-05	3.32E-04	4.15E-05	3.74E-04
	CH_4	7.32E-01	2.14E-01	9.45E-01	3.32E-01	9.69E-02	4.29E-01	3.15E-01	9.18E-02	4.06E-01	1.50E+00	4.39E-01	1.94E+00
	CO_2e (20-year)	58.3	16.4	74.8	26.5	7.5	33.9	25.1	7.1	32.1	119.8	33.8	153.6
	CO_2e (100-year)	23.9	6.4	30.3	10.9	2.9	13.8	10.3	2.7	13.0	49.2	13.1	62.3
	CO_2e (500-year)	11.2	2.7	13.9	5.1	1.2	6.3	4.8	1.2	6.0	23.0	5.5	28.5
Onshore Gas	CO_2	7.18E+00	1.05E+00	8.23E+00	3.26E+00	4.76E-01	3.74E+00	3.09E+00	4.51E-01	3.54E+00	1.48E+01	2.16E+00	1.69E+01
	N_2O	2.13E-04	2.02E-05	2.33E-04	9.66E-05	9.17E-06	1.06E-04	9.16E-05	8.69E-06	1.00E-04	4.38E-04	4.15E-05	4.79E-04
	CH_4	8.21E-01	2.14E-01	1.03E+00	3.72E-01	9.69E-02	4.69E-01	3.53E-01	9.18E-02	4.45E-01	1.69E+00	4.39E-01	2.12E+00
	CO_2e (20-year)	66.3	16.4	82.8	30.1	7.5	37.5	28.5	7.1	35.6	136.3	33.8	170.0
	CO_2e (100-year)	27.8	6.4	34.2	12.6	2.9	15.5	11.9	2.7	14.7	57.0	13.1	70.2
	CO_2e (500-year)	13.5	2.7	16.1	6.1	1.2	7.3	5.8	1.2	6.9	27.6	5.5	33.1
Offshore Gas	CO_2	5.37E+00	1.05E+00	6.42E+00	2.44E+00	4.76E-01	2.91E+00	2.31E+00	4.51E-01	2.76E+00	1.10E+01	2.16E+00	1.32E+01
	N_2O	2.55E-04	2.02E-05	2.75E-04	1.15E-04	9.17E-06	1.25E-04	1.09E-04	8.69E-06	1.18E-04	5.23E-04	4.15E-05	5.64E-04
	CH_4	9.71E-02	2.14E-01	3.11E-01	4.40E-02	9.69E-02	1.41E-01	4.17E-02	9.18E-02	1.34E-01	1.99E-01	4.39E-01	6.38E-01
	CO_2e (20-year)	12.4	16.4	28.9	5.6	7.5	13.1	5.3	7.1	12.4	25.5	33.8	59.3
	CO_2e (100-year)	7.9	6.4	14.3	3.6	2.9	6.5	3.4	2.7	6.1	16.2	13.1	29.3
	CO_2e (500-year)	6.1	2.7	8.8	2.8	1.2	4.0	2.6	1.2	3.8	12.6	5.5	18.1
Assoc. Gas	CO_2	5.04E+00	1.05E+00	6.09E+00	2.29E+00	4.76E-01	2.76E+00	2.17E+00	4.51E-01	2.62E+00	1.04E+01	2.16E+00	1.25E+01
	N_2O	1.42E-04	2.02E-05	1.62E-04	6.42E-05	9.17E-06	7.34E-05	6.09E-05	8.69E-06	6.96E-05	2.91E-04	4.15E-05	3.32E-04
	CH_4	2.82E-01	2.14E-01	4.96E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.80E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.4	16.4	41.8	11.5	7.5	19.0	10.9	7.1	18.0	52.2	33.8	85.9
	CO_2e (100-year)	12.1	6.4	18.5	5.5	2.9	8.4	5.2	2.7	8.0	24.9	13.1	38.1
	CO_2e (500-year)	7.2	2.7	9.9	3.3	1.2	4.5	3.1	1.2	4.2	14.8	5.5	20.3

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
CBM Gas	CO_2	5.45E+00	1.05E+00	6.50E+00	2.47E+00	4.76E-01	2.95E+00	2.34E+00	4.51E-01	2.79E+00	1.12E+01	2.16E+00	1.33E+01
	N_2O	1.55E-04	2.02E-05	1.75E-04	7.03E-05	9.17E-06	7.95E-05	6.67E-05	8.69E-06	7.53E-05	3.18E-04	4.15E-05	3.60E-04
	CH_4	2.86E-01	2.14E-01	5.00E-01	1.30E-01	9.69E-02	2.27E-01	1.23E-01	9.18E-02	2.15E-01	5.88E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.1	16.4	42.5	11.8	7.5	19.3	11.2	7.1	18.3	53.6	33.8	87.4
	CO_2e (100-year)	12.7	6.4	19.1	5.7	2.9	8.6	5.4	2.7	8.2	26.0	13.1	39.1
	CO_2e (500-year)	7.7	2.7	10.3	3.5	1.2	4.7	3.3	1.2	4.4	15.7	5.5	21.2
Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
LNG Gas	CO_2	2.93E+01	1.05E+00	3.04E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.31E+01	6.02E+01	2.16E+00	6.24E+01
	N_2O	3.42E-04	2.02E-05	3.62E-04	1.55E-04	9.17E-06	1.64E-04	1.47E-04	8.69E-06	1.56E-04	7.02E-04	4.15E-05	7.44E-04
	CH_4	2.78E-01	2.14E-01	4.91E-01	1.26E-01	9.69E-02	2.23E-01	1.19E-01	9.18E-02	2.11E-01	5.70E-01	4.39E-01	1.01E+00
	CO_2e (20-year)	49.4	16.4	65.8	22.4	7.5	29.9	21.2	7.1	28.3	101.5	33.8	135.2
	CO_2e (100-year)	36.4	6.4	42.8	16.5	2.9	19.4	15.6	2.7	18.4	74.7	13.1	87.8
	CO_2e (500-year)	31.5	2.7	34.2	14.3	1.2	15.5	13.5	1.2	14.7	64.7	5.5	70.1

Table B-2: Upstream Greenhouse Gas Inventory Results for Marginal Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Onshore Gas	CO_2	5.11E+00	1.05E+00	6.16E+00	2.32E+00	4.76E-01	2.79E+00	2.20E+00	4.51E-01	2.65E+00	1.05E+01	2.16E+00	1.26E+01
	N_2O	1.44E-04	2.02E-05	1.64E-04	6.53E-05	9.17E-06	7.44E-05	6.19E-05	8.69E-06	7.06E-05	2.96E-04	4.15E-05	3.37E-04
	CH_4	3.41E-01	2.14E-01	5.55E-01	1.55E-01	9.69E-02	2.52E-01	1.47E-01	9.18E-02	2.38E-01	7.01E-01	4.39E-01	1.14E+00
	CO_2e (20-year)	29.7	16.4	46.1	13.5	7.5	20.9	12.8	7.1	19.8	61.0	33.8	94.8
	CO_2e (100-year)	13.7	6.4	20.1	6.2	2.9	9.1	5.9	2.7	8.6	28.1	13.1	41.2
	CO_2e (500-year)	7.7	2.7	10.4	3.5	1.2	4.7	3.3	1.2	4.5	15.9	5.5	21.4
Marg. Offshore Gas	CO_2	5.34E+00	1.05E+00	6.39E+00	2.42E+00	4.76E-01	2.90E+00	2.30E+00	4.51E-01	2.75E+00	1.10E+01	2.16E+00	1.31E+01
	N_2O	2.54E-04	2.02E-05	2.74E-04	1.15E-04	9.17E-06	1.24E-04	1.09E-04	8.69E-06	1.18E-04	5.21E-04	4.15E-05	5.62E-04
	CH_4	9.01E-02	2.14E-01	3.04E-01	4.09E-02	9.69E-02	1.38E-01	3.87E-02	9.18E-02	1.31E-01	1.85E-01	4.39E-01	6.24E-01
	CO_2e (20-year)	11.9	16.4	28.3	5.4	7.5	12.9	5.1	7.1	12.2	24.4	33.8	58.2
	CO_2e (100-year)	7.7	6.4	14.1	3.5	2.9	6.4	3.3	2.7	6.0	15.8	13.1	28.9
	CO_2e (500-year)	6.1	2.7	8.7	2.8	1.2	4.0	2.6	1.2	3.8	12.5	5.5	18.0

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Assoc. Gas	CO_2	4.91E+00	1.05E+00	5.96E+00	2.23E+00	4.76E-01	2.70E+00	2.11E+00	4.51E-01	2.56E+00	1.01E+01	2.16E+00	1.22E+01
	N_2O	1.37E-04	2.02E-05	1.57E-04	6.22E-05	9.17E-06	7.14E-05	5.90E-05	8.69E-06	6.77E-05	2.82E-04	4.15E-05	3.23E-04
	CH_4	2.82E-01	2.14E-01	4.95E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.78E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.2	16.4	41.7	11.4	7.5	18.9	10.8	7.1	17.9	51.8	33.8	85.6
	CO_2e (100-year)	12.0	6.4	18.4	5.4	2.9	8.3	5.2	2.7	7.9	24.6	13.1	37.8
	CO_2e (500-year)	7.1	2.7	9.7	3.2	1.2	4.4	3.0	1.2	4.2	14.5	5.5	20.0
Marg. Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	SF_6	6.49E-09	2.50E-09	8.99E-09	2.94E-09	1.13E-09	4.08E-09	2.79E-09	1.07E-09	3.86E-09	1.33E-08	5.13E-09	1.85E-08
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
Marg. Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
Marg. CBM Gas	CO_2	5.67E+00	1.05E+00	6.72E+00	2.57E+00	4.76E-01	3.05E+00	2.44E+00	4.51E-01	2.89E+00	1.16E+01	2.16E+00	1.38E+01
	N_2O	1.62E-04	2.02E-05	1.83E-04	7.36E-05	9.17E-06	8.28E-05	6.98E-05	8.69E-06	7.85E-05	3.33E-04	4.15E-05	3.75E-04
	CH_4	2.88E-01	2.14E-01	5.02E-01	1.31E-01	9.69E-02	2.28E-01	1.24E-01	9.18E-02	2.16E-01	5.92E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.5	16.4	42.9	12.0	7.5	19.5	11.4	7.1	18.4	54.4	33.8	88.1
	CO_2e (100-year)	12.9	6.4	19.3	5.9	2.9	8.8	5.6	2.7	8.3	26.6	13.1	39.7
	CO_2e (500-year)	7.9	2.7	10.6	3.6	1.2	4.8	3.4	1.2	4.5	16.2	5.5	21.7
Marg. LNG Gas	CO_2	2.93E+01	1.05E+00	3.03E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.30E+01	6.01E+01	2.16E+00	6.23E+01
	N_2O	3.41E-04	2.02E-05	3.61E-04	1.54E-04	9.17E-06	1.64E-04	1.46E-04	8.69E-06	1.55E-04	7.00E-04	4.15E-05	7.41E-04
	CH_4	2.70E-01	2.14E-01	4.83E-01	1.22E-01	9.69E-02	2.19E-01	1.16E-01	9.18E-02	2.08E-01	5.54E-01	4.39E-01	9.92E-01
	CO_2e (20-year)	48.8	16.4	65.2	22.1	7.5	29.6	21.0	7.1	28.0	100.2	33.8	133.9
	CO_2e (100-year)	36.1	6.4	42.5	16.4	2.9	19.3	15.5	2.7	18.3	74.2	13.1	87.3
	CO_2e (500-year)	31.4	2.7	34.1	14.2	1.2	15.4	13.5	1.2	14.6	64.5	5.5	69.9

Table B-3: Upstream Greenhouse Gas Inventory Results for Coal

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Coal	CO_2	1.32E+00	1.33E+00	2.64E+00	5.97E-01	6.02E-01	1.20E+00	5.66E-01	5.71E-01	1.14E+00
	N_2O	5.29E-04	3.21E-05	5.61E-04	2.40E-04	1.46E-05	2.54E-04	2.27E-04	1.38E-05	2.41E-04
	CH_4	3.78E-01	7.23E-04	3.79E-01	1.72E-01	3.28E-04	1.72E-01	1.63E-01	3.11E-04	1.63E-01
	CO_2e (20-year)	28.7	1.4	30.1	13.0	0.6	13.7	12.3	0.6	12.9
	CO_2e (100-year)	10.9	1.4	12.3	5.0	0.6	5.6	4.7	0.6	5.3
	CO_2e (500-year)	4.3	1.3	5.6	1.9	0.6	2.5	1.8	0.6	2.4
Illinois No. 6 Coal	CO_2	2.53E+00	1.33E+00	3.86E+00	1.15E+00	6.02E-01	1.75E+00	1.09E+00	5.71E-01	1.66E+00
	N_2O	3.97E-05	3.21E-05	7.18E-05	1.80E-05	1.46E-05	3.26E-05	1.71E-05	1.38E-05	3.09E-05
	CH_4	9.40E-01	7.23E-04	9.41E-01	4.27E-01	3.28E-04	4.27E-01	4.04E-01	3.11E-04	4.05E-01
	SF_6	4.98E-07	5.47E-12	4.98E-07	2.26E-07	2.48E-12	2.26E-07	2.14E-07	2.35E-12	2.14E-07
	CO_2e (20-year)	70.3	1.4	71.7	31.9	0.6	32.5	30.2	0.6	30.8
	CO_2e (100-year)	26.1	1.4	27.4	11.8	0.6	12.4	11.2	0.6	11.8
	CO_2e (500-year)	9.7	1.3	11.0	4.4	0.6	5.0	4.2	0.6	4.7
PRB Coal	CO_2	7.73E-01	1.33E+00	2.10E+00	3.51E-01	6.02E-01	9.53E-01	3.32E-01	5.71E-01	9.03E-01
	N_2O	7.48E-04	3.21E-05	7.80E-04	3.39E-04	1.46E-05	3.54E-04	3.22E-04	1.38E-05	3.35E-04
	CH_4	1.26E-01	7.23E-04	1.26E-01	5.70E-02	3.28E-04	5.74E-02	5.41E-02	3.11E-04	5.44E-02
	CO_2e (20-year)	10.0	1.4	11.4	4.6	0.6	5.2	4.3	0.6	4.9
	CO_2e (100-year)	4.1	1.4	5.5	1.9	0.6	2.5	1.8	0.6	2.4
	CO_2e (500-year)	1.8	1.3	3.2	0.8	0.6	1.4	0.8	0.6	1.4

Table B-4: Upstream Greenhouse Gas Inventory Results for Natural Gas-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Gas)	CO_2	5.81E+01	1.01E+01	8.75E+02	0.00E+00	9.43E+02	2.63E+01	4.60E+00	3.97E+02	0.00E+00	4.28E+02	7.31E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	1.81E-03	1.96E-04	2.45E-03	0.00E+00	4.45E-03	8.22E-04	8.88E-05	1.11E-03	0.00E+00	2.02E-03	2.28E-04	2.47E-05	3.08E-04	0.00E+00	5.61E-04
	CH_4	6.31E+00	2.09E+00	2.44E-02	0.00E+00	8.42E+00	2.86E+00	9.46E-01	1.11E-02	0.00E+00	3.82E+00	7.95E-01	2.63E-01	3.07E-03	0.00E+00	1.06E+00
	SF_6	4.80E-07	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.18E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	6.04E-08	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	513.0	160.4	877.0	5.2	1,555.6	232.7	72.8	397.8	2.3	705.6	64.6	20.2	110.5	0.6	196.0
	CO_2e (100-year)	216.4	62.4	875.9	7.2	1,161.8	98.2	28.3	397.3	3.3	527.0	27.3	7.9	110.4	0.9	146.4
	CO_2e (500-year)	106.3	26.0	875.1	10.3	1,017.7	48.2	11.8	396.9	4.7	461.6	13.4	3.3	110.3	1.3	128.2
Fleet Baseload (Conv. Gas)	CO_2	6.22E+01	1.01E+01	8.75E+02	0.00E+00	9.47E+02	2.82E+01	4.60E+00	3.97E+02	0.00E+00	4.30E+02	7.84E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	2.10E-03	1.96E-04	2.45E-03	0.00E+00	4.75E-03	9.55E-04	8.88E-05	1.11E-03	0.00E+00	2.15E-03	2.65E-04	2.47E-05	3.08E-04	0.00E+00	5.98E-04
	CH_4	5.26E+00	2.09E+00	2.44E-02	0.00E+00	7.37E+00	2.38E+00	9.46E-01	1.11E-02	0.00E+00	3.34E+00	6.62E-01	2.63E-01	3.07E-03	0.00E+00	9.28E-01
	SF_6	5.26E-08	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.39E-08	1.99E-12	0.00E+00	1.43E-04	1.43E-04	6.63E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	441.3	160.4	877.0	5.2	1,483.9	200.2	72.8	397.8	2.3	673.1	55.6	20.2	110.5	0.6	187.0
	CO_2e (100-year)	194.3	62.4	875.9	7.2	1,139.7	88.1	28.3	397.3	3.3	517.0	24.5	7.9	110.4	0.9	143.6
	CO_2e (500-year)	102.5	26.0	875.1	10.3	1,013.9	46.5	11.8	396.9	4.7	459.9	12.9	3.3	110.3	1.3	127.8

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (UnConv. Gas)	CO_2	5.47E+01	1.01E+01	8.75E+02	0.00E+00	9.39E+02	2.48E+01	4.60E+00	3.97E+02	0.00E+00	4.26E+02	6.90E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.58E-03	1.96E-04	2.45E-03	0.00E+00	4.22E-03	7.17E-04	8.88E-05	1.11E-03	0.00E+00	1.91E-03	1.99E-04	2.47E-05	3.08E-04	0.00E+00	5.32E-04
	CH_4	7.15E+00	2.09E+00	2.44E-02	0.00E+00	9.26E+00	3.24E+00	9.46E-01	1.11E-02	0.00E+00	4.20E+00	9.01E-01	2.63E-01	3.07E-03	0.00E+00	1.17E+00
	SF_6	8.20E-07	4.38E-12	0.00E+00	3.16E-04	3.17E-04	3.72E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	1.03E-07	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	570.1	160.4	877.0	5.2	1,612.7	258.6	72.8	397.8	2.3	731.5	71.8	20.2	110.5	0.6	203.2
	CO_2e (100-year)	234.0	62.4	875.9	7.2	1,179.5	106.1	28.3	397.3	3.3	535.0	29.5	7.9	110.4	0.9	148.6
	CO_2e (500-year)	109.4	26.0	875.1	10.3	1,020.8	49.6	11.8	396.9	4.7	463.0	13.8	3.3	110.3	1.3	128.6
Fleet Baseload (Marg. Onshore Gas)	CO_2	4.99E+01	1.01E+01	8.75E+02	0.00E+00	9.35E+02	2.26E+01	4.60E+00	3.97E+02	0.00E+00	4.24E+02	6.29E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.41E-03	1.96E-04	2.45E-03	0.00E+00	4.05E-03	6.38E-04	8.88E-05	1.11E-03	0.00E+00	1.84E-03	1.77E-04	2.47E-05	3.08E-04	0.00E+00	5.10E-04
	CH_4	3.33E+00	2.09E+00	2.44E-02	0.00E+00	5.44E+00	1.51E+00	9.46E-01	1.11E-02	0.00E+00	2.47E+00	4.20E-01	2.63E-01	3.07E-03	0.00E+00	6.86E-01
	SF_6	9.27E-09	4.38E-12	0.00E+00	3.16E-04	3.16E-04	4.20E-09	1.99E-12	0.00E+00	1.43E-04	1.43E-04	1.17E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	290.4	160.4	877.0	5.2	1,332.9	131.7	72.8	397.8	2.3	604.6	36.6	20.2	110.5	0.6	167.9
	CO_2e (100-year)	133.7	62.4	875.9	7.2	1,079.1	60.6	28.3	397.3	3.3	489.5	16.8	7.9	110.4	0.9	136.0
	CO_2e (500-year)	75.5	26.0	875.1	10.3	986.9	34.2	11.8	396.9	4.7	447.6	9.5	3.3	110.3	1.3	124.3
GTSC (Avg. Gas)	CO_2	7.26E+01	1.27E+01	1.33E+03	0.00E+00	1.42E+03	3.29E+01	5.75E+00	6.04E+02	0.00E+00	6.42E+02	9.15E+00	1.60E+00	1.68E+02	0.00E+00	1.78E+02
	N_2O	2.27E-03	2.45E-04	2.86E-05	0.00E+00	2.54E-03	1.03E-03	1.11E-04	1.30E-05	0.00E+00	1.15E-03	2.86E-04	3.08E-05	3.61E-06	0.00E+00	3.20E-04
	CH_4	7.90E+00	2.61E+00	2.64E-03	0.00E+00	1.05E+01	3.58E+00	1.18E+00	1.20E-03	0.00E+00	4.77E+00	9.95E-01	3.29E-01	3.32E-04	0.00E+00	1.32E+00
	SF_6	6.00E-07	5.48E-12	4.34E-08	3.16E-04	3.17E-04	2.72E-07	2.48E-12	1.97E-08	1.43E-04	1.44E-04	7.56E-08	6.90E-13	5.47E-09	3.98E-05	3.99E-05
	CO_2e (20-year)	641.8	200.7	1,330.7	5.2	2,178.4	291.1	91.0	603.6	2.3	988.1	80.9	25.3	167.7	0.6	274.5
	CO_2e (100-year)	270.7	78.0	1,330.6	7.2	1,686.6	122.8	35.4	603.6	3.3	765.0	34.1	9.8	167.7	0.9	212.5
	CO_2e (500-year)	133.0	32.6	1,330.6	10.3	1,506.4	60.3	14.8	603.5	4.7	683.3	16.8	4.1	167.6	1.3	189.8
NGCC (Avg. Gas)	CO_2	4.71E+01	8.23E+00	8.66E+02	0.00E+00	9.22E+02	2.14E+01	3.73E+00	3.93E+02	0.00E+00	4.18E+02	5.94E+00	1.04E+00	1.09E+02	0.00E+00	1.16E+02
	N_2O	1.47E-03	1.59E-04	3.33E-05	0.00E+00	1.66E-03	6.67E-04	7.21E-05	1.51E-05	0.00E+00	7.55E-04	1.85E-04	2.00E-05	4.20E-06	0.00E+00	2.10E-04
	CH_4	5.12E+00	1.69E+00	1.31E-03	0.00E+00	6.82E+00	2.32E+00	7.68E-01	5.94E-04	0.00E+00	3.09E+00	6.46E-01	2.13E-01	1.65E-04	0.00E+00	8.59E-01
	SF_6	3.89E-07	3.55E-12	7.55E-07	3.16E-04	3.17E-04	1.77E-07	1.61E-12	3.42E-07	1.43E-04	1.44E-04	4.91E-08	4.48E-13	9.51E-08	3.98E-05	4.00E-05
	CO_2e (20-year)	416.5	130.2	866.5	5.2	1,418.5	188.9	59.1	393.1	2.3	643.4	52.5	16.4	109.2	0.6	178.7
	CO_2e (100-year)	175.7	50.6	866.5	7.2	1,100.0	79.7	23.0	393.0	3.3	499.0	22.1	6.4	109.2	0.9	138.6
	CO_2e (500-year)	86.3	21.1	866.5	10.3	984.2	39.2	9.6	393.0	4.7	446.4	10.9	2.7	109.2	1.3	124.0
NGCC/ccs (Avg. Gas)	CO_2	5.52E+01	9.65E+00	1.13E+02	0.00E+00	1.78E+02	2.51E+01	4.38E+00	5.13E+01	0.00E+00	8.07E+01	6.96E+00	1.22E+00	1.42E+01	0.00E+00	2.24E+01
	N_2O	1.72E-03	1.86E-04	5.18E-05	0.00E+00	1.96E-03	7.82E-04	8.45E-05	2.35E-05	0.00E+00	8.90E-04	2.17E-04	2.35E-05	6.53E-06	0.00E+00	2.47E-04
	CH_4	6.01E+00	1.99E+00	1.71E-03	0.00E+00	7.99E+00	2.72E+00	9.01E-01	7.78E-04	0.00E+00	3.63E+00	7.57E-01	2.50E-01	2.16E-04	0.00E+00	1.01E+00
	SF_6	4.57E-07	4.16E-12	8.81E-07	3.16E-04	3.17E-04	2.07E-07	1.89E-12	4.00E-07	1.43E-04	1.44E-04	5.75E-08	5.25E-13	1.11E-07	3.98E-05	4.00E-05
	CO_2e (20-year)	488.2	152.7	113.2	5.2	759.2	221.5	69.2	51.3	2.3	344.4	61.5	19.2	14.3	0.6	95.7
	CO_2e (100-year)	205.9	59.3	113.1	7.2	385.6	93.4	26.9	51.3	3.3	174.9	25.9	7.5	14.3	0.9	48.6
	CO_2e (500-year)	101.2	24.8	113.1	10.3	249.3	45.9	11.2	51.3	4.7	113.1	12.7	3.1	14.2	1.3	31.4

Table B-5: Upstream Greenhouse Gas Inventory Results for Coal-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Coal)	CO_2	1.38E+01	1.39E+01	2.33E+03	0.00E+00	2.35E+03	6.26E+00	6.31E+00	1.06E+03	0.00E+00	1.07E+03	1.74E+00	1.75E+00	2.93E+02	0.00E+00	2.97E+02
	N_2O	5.54E-03	3.36E-04	3.99E-02	0.00E+00	4.58E-02	2.51E-03	1.53E-04	1.81E-02	0.00E+00	2.08E-02	6.98E-04	4.24E-05	5.03E-03	0.00E+00	5.77E-03
	CH_4	3.96E+00	7.57E-03	2.67E-02	0.00E+00	4.00E+00	1.80E+00	3.43E-03	1.21E-02	0.00E+00	1.81E+00	4.99E-01	9.54E-04	3.37E-03	0.00E+00	5.04E-01
	SF_6	1.77E-06	5.73E-11	0.00E+00	3.16E-04	3.18E-04	8.03E-07	2.60E-11	0.00E+00	1.43E-04	1.44E-04	2.23E-07	7.22E-12	0.00E+00	3.98E-05	4.00E-05
	CO_2e (20-year)	300.8	14.5	2,340.1	5.2	2,660.6	136.4	6.6	1,061.5	2.3	1,206.8	37.9	1.8	294.9	0.6	335.2
	CO_2e (100-year)	114.6	14.2	2,339.2	7.2	2,475.2	52.0	6.4	1,061.1	3.3	1,122.7	14.4	1.8	294.7	0.9	311.9
	CO_2e (500-year)	44.8	14.0	2,333.0	10.3	2,402.1	20.3	6.4	1,058.2	4.7	1,089.6	5.6	1.8	294.0	1.3	302.7
EXPC (Illinois No. 6 Coal)	CO_2	2.24E+01	1.18E+01	2.23E+03	0.00E+00	2.27E+03	1.02E+01	5.34E+00	1.01E+03	0.00E+00	1.03E+03	2.83E+00	1.48E+00	2.81E+02	0.00E+00	2.85E+02
	N_2O	3.52E-04	2.85E-04	3.77E-02	0.00E+00	3.83E-02	1.60E-04	1.29E-04	1.71E-02	0.00E+00	1.74E-02	4.44E-05	3.59E-05	4.75E-03	0.00E+00	4.83E-03
	CH_4	8.35E+00	6.42E-03	2.51E-02	0.00E+00	8.38E+00	3.79E+00	2.91E-03	1.14E-02	0.00E+00	3.80E+00	1.05E+00	8.08E-04	3.17E-03	0.00E+00	1.06E+00
	SF_6	4.42E-06	4.85E-11	6.11E-07	3.16E-04	3.21E-04	2.00E-06	2.20E-11	2.77E-07	1.43E-04	1.46E-04	5.57E-07	6.11E-12	7.70E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	623.7	12.3	2,243.5	5.2	2,884.7	282.9	5.6	1,017.6	2.3	1,308.5	78.6	1.6	282.7	0.6	363.5
	CO_2e (100-year)	231.4	12.0	2,242.7	7.2	2,493.3	104.9	5.5	1,017.3	3.3	1,130.9	29.2	1.5	282.6	0.9	314.1
	CO_2e (500-year)	86.1	11.9	2,236.8	10.3	2,345.0	39.0	5.4	1,014.6	4.7	1,063.7	10.8	1.5	281.8	1.3	295.5
IGCC (Illinois No. 6 Coal)	CO_2	1.98E+01	1.04E+01	1.89E+03	0.00E+00	1.92E+03	8.98E+00	4.72E+00	8.57E+02	0.00E+00	8.71E+02	2.49E+00	1.31E+00	2.38E+02	0.00E+00	2.42E+02
	N_2O	3.11E-04	2.52E-04	4.67E-05	0.00E+00	6.09E-04	1.41E-04	1.14E-04	2.12E-05	0.00E+00	2.76E-04	3.92E-05	3.17E-05	5.89E-06	0.00E+00	7.68E-05
	CH_4	7.37E+00	5.66E-03	9.58E-03	0.00E+00	7.38E+00	3.34E+00	2.57E-03	4.35E-03	0.00E+00	3.35E+00	9.28E-01	7.13E-04	1.21E-03	0.00E+00	9.30E-01
	SF_6	3.90E-06	4.28E-11	7.69E-07	3.16E-04	3.21E-04	1.77E-06	1.94E-11	3.49E-07	1.43E-04	1.45E-04	4.91E-07	5.40E-12	9.69E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	550.4	10.9	1,890.8	5.2	2,457.2	249.7	4.9	857.7	2.3	1,114.6	69.3	1.4	238.2	0.6	309.6
	CO_2e (100-year)	204.2	10.6	1,890.4	7.2	2,112.4	92.6	4.8	857.5	3.3	958.2	25.7	1.3	238.2	0.9	266.2
	CO_2e (500-year)	76.0	10.5	1,890.2	10.3	1,987.0	34.5	4.8	857.4	4.7	901.3	9.6	1.3	238.2	1.3	250.4
IGCC/ccs (Illinois No. 6 Coal)	CO_2	2.33E+01	1.22E+01	2.46E+02	0.00E+00	2.81E+02	1.06E+01	5.55E+00	1.11E+02	0.00E+00	1.28E+02	2.94E+00	1.54E+00	3.10E+01	0.00E+00	3.54E+01
	N_2O	3.66E-04	2.96E-04	9.13E-05	0.00E+00	7.54E-04	1.66E-04	1.34E-04	4.14E-05	0.00E+00	3.42E-04	4.61E-05	3.73E-05	1.15E-05	0.00E+00	9.50E-05
	CH_4	8.67E+00	6.67E-03	1.15E-02	0.00E+00	8.69E+00	3.93E+00	3.02E-03	5.20E-03	0.00E+00	3.94E+00	1.09E+00	8.40E-04	1.45E-03	0.00E+00	1.10E+00
	SF_6	4.59E-06	5.04E-11	8.72E-07	3.16E-04	3.21E-04	2.08E-06	2.29E-11	3.96E-07	1.43E-04	1.46E-04	5.78E-07	6.35E-12	1.10E-07	3.98E-05	4.05E-05
	CO_2e (20-year)	648.1	12.8	246.6	5.2	912.7	294.0	5.8	111.9	2.3	414.0	81.7	1.6	31.1	0.6	115.0
	CO_2e (100-year)	240.4	12.5	246.1	7.2	506.2	109.0	5.7	111.6	3.3	229.6	30.3	1.6	31.0	0.9	63.8
	CO_2e (500-year)	89.5	12.3	245.9	10.3	358.0	40.6	5.6	111.5	4.7	162.4	11.3	1.6	31.0	1.3	45.1

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
SCPC (Illinois No. 6 Coal)	CO_2	1.94E+01	1.02E+01	1.91E+03	0.00E+00	1.94E+03	8.78E+00	4.61E+00	8.66E+02	0.00E+00	8.79E+02	2.44E+00	1.28E+00	2.41E+02	0.00E+00	2.44E+02
	N_2O	3.04E-04	2.46E-04	6.99E-05	0.00E+00	6.20E-04	1.38E-04	1.12E-04	3.17E-05	0.00E+00	2.81E-04	3.83E-05	3.10E-05	8.81E-06	0.00E+00	7.81E-05
	CH_4	7.20E+00	5.53E-03	8.98E-03	0.00E+00	7.22E+00	3.27E+00	2.51E-03	4.07E-03	0.00E+00	3.27E+00	9.07E-01	6.97E-04	1.13E-03	0.00E+00	9.09E-01
	SF_6	3.81E-06	4.19E-11	8.26E-07	3.16E-04	3.21E-04	1.73E-06	1.90E-11	3.74E-07	1.43E-04	1.45E-04	4.80E-07	5.27E-12	1.04E-07	3.98E-05	4.04E-05
	CO_2e (20-year)	538.0	10.6	1,910.1	5.2	2,463.9	244.0	4.8	866.4	2.3	1,117.6	67.8	1.3	240.7	0.6	310.5
	CO_2e (100-year)	199.6	10.4	1,909.7	7.2	2,126.9	90.5	4.7	866.2	3.3	964.7	25.1	1.3	240.6	0.9	268.0
	CO_2e (500-year)	74.3	10.2	1,909.5	10.3	2,004.3	33.7	4.6	866.2	4.7	909.2	9.4	1.3	240.6	1.3	252.5
SCPC/ccs (Illinois No. 6 Coal)	CO_2	2.78E+01	1.46E+01	3.02E+02	0.00E+00	3.45E+02	1.26E+01	6.63E+00	1.37E+02	0.00E+00	1.56E+02	3.51E+00	1.84E+00	3.81E+01	0.00E+00	4.34E+01
	N_2O	4.37E-04	3.53E-04	1.07E-04	0.00E+00	8.97E-04	1.98E-04	1.60E-04	4.85E-05	0.00E+00	4.07E-04	5.50E-05	4.45E-05	1.35E-05	0.00E+00	1.13E-04
	CH_4	1.04E+01	7.95E-03	9.79E-03	0.00E+00	1.04E+01	4.69E+00	3.61E-03	4.44E-03	0.00E+00	4.70E+00	1.30E+00	1.00E-03	1.23E-03	0.00E+00	1.31E+00
	SF_6	5.48E-06	6.02E-11	8.34E-07	3.16E-04	3.22E-04	2.48E-06	2.73E-11	3.78E-07	1.43E-04	1.46E-04	6.90E-07	7.58E-12	1.05E-07	3.98E-05	4.06E-05
	CO_2e (20-year)	773.3	15.3	302.8	5.2	1,096.5	350.7	6.9	137.4	2.3	497.4	97.4	1.9	38.2	0.6	138.2
	CO_2e (100-year)	286.8	14.9	302.4	7.2	611.3	130.1	6.8	137.2	3.3	277.3	36.1	1.9	38.1	0.9	77.0
	CO_2e (500-year)	106.7	14.7	302.2	10.3	434.0	48.4	6.7	137.1	4.7	196.8	13.4	1.9	38.1	1.3	54.7

Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production

Summary and Analysis of API and ANGA Survey Responses

Terri Shires and Miriam Lev-On
URS Corporation and The LEVON Group

FINAL REPORT
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Executive Summary

This document presents the results from a collaborative effort among members of the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) to gather data on key natural gas production activities and equipment emission sources - including unconventional natural gas production - that are essential to developing estimates of methane emissions from upstream natural gas production.

API and ANGA members undertook this effort as part of an overall priority to develop new and better data about natural gas production and make this information available to the public. This information acquired added importance in 2011, when the EPA released an inventory of U.S. greenhouse gases (GHG) emissions that substantially increased estimates of methane emissions from Petroleum and Natural Gas Systems. Public comments submitted by both trade associations reflected a number of concerns – most notably that EPA's estimates were based on a small set of data submitted by a limited number of companies in a different context (i.e., data not developed for the purpose of estimating nationwide emissions).

The API/ANGA data set (also referred to as ANGA/API) provides data on 91,000 wells distributed over a broad geographic area and operated by over 20 companies. This represents nearly one-fifth (18.8%) of the estimated number of total wells used in EPA's 2010 emissions inventory.[1] The ANGA/API data set is also more than 10 times larger than the set of wells in one of EPA's key data sources taken from an older Natural Gas Star sample that was never intended for developing nationwide emissions estimates. ***Although more and better data efforts will still be needed, API/ANGA members believe this current collaborative effort is the most comprehensive data set compiled for natural gas operations.***

As Table ES-1 demonstrates, survey results in two source categories – liquids unloading and unconventional gas well re-fracture rates - substantially lower EPA's estimated emissions from natural gas production and shift Natural Gas Systems from the largest contributor of methane emissions to the second largest (behind Enteric Fermentation, which is a consequence of bovine digestion).[2] The right-hand column of this table shows the impact of ANGA/API data on the estimated emissions for each source category. Gas well liquids unloading and the rate at which unconventional gas wells are re-fractured are key contributors to the overall GHG emissions estimated by EPA in the national emissions inventory. For example, methane emissions from liquids unloading and unconventional well re-fracturing accounted for 59% of EPA's estimate for overall natural gas production sector methane emissions. Overall, API/ANGA activity data for these two source categories indicate that EPA estimates of potential emissions from the production sector of "Natural Gas Systems" would be 50% lower if EPA were to use ANGA/API's larger and more recent survey results.

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[1] EPA's 2010 national inventory indicates a total of 484,795 gas wells (EPA, 2012).

[2] Table ES-2 of the 2010 national inventory (EPA, 2012).

TABLE ES-1. EMISSION COMPARISON BETWEEN EPA AND INDUSTRY DATA

Source Category	EPA		API/ANGA		Impact on Source Category Emissions
	Metric tons of CH4	% of EPA Emissions Total	Metric tons of CH4	% of Revised Emissions Total	API & ANGA - EPA EPA % Difference
Gas Wells Liquids Unloading	4,501,465 *	51%	637,766	14%	-86%
Unconventional Well Re-fracture Rates	712,605 *	8%	197,311	4%	-72%
Other Production Sector Emissions**	3,585,600	41%	3,585,600	81%	
Total Production Sector Emissions	8,799,670		4,420,677		-50%

* EPA's estimates are adjusted to industry standard conditions of 60 degrees F and 14.7 psia for comparison to the ANGA/API emission estimates.

**The "Other Production Sector Emissions" are comprised of over 30 different source categories detailed in Table A-129 in the Annex of the EPA's 2012 national inventory. The "Other Production Sector Emissions" are the same values for this comparison between the EPA national inventory and the API/ANGA survey to focus the comparison on quantified differences in emission estimates for gas well liquids unloading and unconventional well re-fracture rates.

As mentioned above, the differences between EPA and ANGA/API estimates hinge on the following key differences in activity data and thus considerably impact overall emissions from Natural Gas Systems:

- ***Liquids unloading and venting.*** API/ANGA data showed lower average vent times as well as a lower percentage of wells with plunger lifts and wells venting to the atmosphere than EPA assumed. This is particularly significant because liquids unloading accounted for 51% of EPA's total "Natural Gas Systems" methane emissions in the 2010 inventory. Applying emission factors based on ANGA/API data reduces the calculated emissions for this source by 86% (from 4,501,465 metric tons of CH_4 to 637,766 metric tons of CH_4 when compared on an equivalent basis) from EPA's 2010 national GHG inventory.
- ***Re-fracture rates for unconventional wells***. API/ANGA members collected data on re-fracture rates for unconventional wells in two phases. The first phase collected data for all well types (conventional and unconventional), while the second phase targeted unconventional gas wells. Both phases of the survey data show significantly lower rates of well re-fracturing than the 10% assumption used by EPA. As discussed in detail in this report, the re-fracture rate varied from 0.7% to 2.3%. The second phase of the survey gathered data from only unconventional well activity and using the re-fracture rate data from this second phase of the ANGA/API survey reduces the national emission estimate

for this source category by 72%, - from 712,605 metric tons of CH_4 to 197,311 metric tons of CH_4 when compared on an equivalent basis.

This report also discusses an important related concern that the government lacks a single coordinated and cohesive estimate of well completions and well counts. Although the 2010 national GHG inventory appears to under-represent the number of well completions according to the numbers reported through both the API/ANGA data and IHS CERA, differences in national well data reporting systems make it difficult to accurately investigate well completion differences with any certainty. The EPA inventory, which uses data from HPDI, and the Energy Information Administration (in addition to privately sourced data) all report different well counts that do not consistently distinguish between conventional and unconventional wells. Without a consistent measure for the quantity and type of wells, it is difficult to be confident of the accuracy of the number of wells that are completed annually, let alone the amount of emissions from them. Natural gas producers strongly believe that the effects of any possible under-representation of well completions will be offset by a more realistic emission factor for the rate of emissions per well.

This survey also collected data on centrifugal compressors and pneumatic controllers. While the sample sizes are too small to make strong conclusions, the results discussed in the body of the report indicate that further research is necessary to accurately account for the different types of equipment in this area (e.g., wet vs. dry seal centrifugal compressors and "high bleed," "low bleed," and "intermittent bleed" pneumatic controllers).

As government and industry move forward in addressing emissions from unconventional gas operations, three key points are worth noting:

- ***In addition to the voluntary measures undertaken by industry, more data will become available in the future.*** Emission reporting requirements under Subpart W of the national Greenhouse Gas Reporting Program (GHGRP) went into effect January 1, 2011 with the first reporting due in the fall of 2012. As implementation of the GHGRP progresses from year to year, the natural gas industry will report more complete and more accurate data. If EPA makes use of the data submitted and transparently communicates their analyses, ANGA/API members believe this will increase public confidence in the emissions estimated for key emission source categories of the Natural Gas Systems sector.
- ***Industry has a continuous commitment to improvement.*** It is clear that companies are not waiting for regulatory mandates or incentives to upgrade equipment, or to alter practices like venting and flaring in favor of capturing methane where practical. Instead, operators are seizing opportunities to reduce the potential environmental impacts of their operations. Industry is therefore confident that additional, systematic collection of production sector activity data will not only help target areas for future reductions but also demonstrate significant voluntary progress toward continually 'greener' operations.
- ***Members of industry participating in this survey are committed to providing information about the new and fast-changing area of unconventional oil and gas operations. API and ANGA members look forward to working with the EPA to revise current assessment methodologies as well as promote the accurate and defensible uses of existing data sources.***

1. Overview

The accuracy of GHG emission estimates from unconventional natural gas production has become a matter of increasing public debate due in part to limited data, variability in the complex calculation methodologies, and assumptions used to approximate emissions where measurements in large part are sparse to date. Virtually all operators have comprehensive methane mitigation strategies; however, beyond the requirements of the Environmental Protection Agency's (EPA) Mandatory Reporting Rule or incentives of programs like the EPA's Natural Gas Star program, data is often not gathered in a unified way that facilitates comparison among companies.

In an attempt to provide additional data and identify uncertainty in existing data sets, the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) began a joint study on methane (CH_4) emissions from unconventional gas operations in July 2011. The first part of this section offers context to the decision to conduct this survey, while the second offers a brief introduction to the survey itself.

1.1 Context

Shale gas will undoubtedly play a key role in America's energy future and therefore additional information must be collected to quantify the methane emissions from both conventional and unconventional natural gas production. Meaningful, publicly available data is a priority, especially in light of EPA's 2011 revision of its calculation methodology for Natural Gas Systems in the 2009 national inventory (EPA, 2011b). (EPA added two new sources for unconventional gas well completions and workovers, and also significantly revised its estimates for liquids unloading and made adjustments to other source categories.) These changes substantially increased EPA's estimated GHG emissions for the production sector of the Natural Gas Systems by 204%.

Industry was alarmed by the upward adjustment, especially since previous EPA estimates had been based on a 1996 report prepared by the EPA and GRI – and did not take into account the considerable improvements in equipment and industry practice that have occurred in the fifteen years between 1996 and 2011 (GRI, 1996).

An EPA technical note to the 2009 inventory attributed the changes to adjustments in calculation methods for existing sources, including gas well liquids unloading, condensate storage tanks, and centrifugal compressor seals. EPA also added two new sources not previously included in its inventories, namely unconventional gas well completions and workovers (re-completions) (EPA, 2011e).

Industry did not have an adequate opportunity to examine EPA's rationale for the new emissions factor prior to its initial release. Unlike changes in regulatory requirements, EPA is not required to initiate a formal comment process for changes in methodologies like emission factors and calculations methods in the national GHG inventory. As such, EPA is not compelled to incorporate or consider input provided by stakeholders and experts. Indeed, changes to methodologies are often made without the benefit of dialogue or expert review. Although EPA further acknowledged in the 2010 inventory (released in 2012), that their natural gas calculations needed work, their practice is to continue using the same numbers until adjusted estimates have been made. It is important to note that EPA has indicated a willingness to engage and discuss this matter with some members of industry; however, no time frame has yet been determined for this discussion.

Under the best of circumstances, EPA had remarkably little information to draw on in determining their new emission factor. Input from industry on this topic was not directly solicited. Specific guidance also did not exist on the international level, nor was it available from other national regulators. A review of the Intergovernmental Panel on Climate Change (IPCC) and other inventories submitted to the United Nations Framework Convention on Climate Change (UNFCCC) indicate that the U.S. is currently the only country to date to differentiate between conventional and unconventional natural gas production. Regulators, academics, and environmentalists around the world therefore considered the new estimated emission factor as an unprecedented development in a controversial issue.

Widespread criticism of the figures revealed problematic methodology and less justification for the underlying numbers than originally anticipated. In a paper entitled *Mismeasuring Methane*, the well-respected energy consultancy IHS CERA succinctly detailed several concerns about the revisions – most notably that EPA's new estimate was based on only four (4) data points that natural gas well operators had submitted voluntarily under the Natural Gas Star Program, which highlights emissions reductions. Together, the four data points cover approximately 8,880 wells – or roughly 2% of those wells covered in the EPA's national greenhouse gas inventory. Those numbers, which were submitted in the context of showcasing achieved emissions reductions and not to estimate emissions, were then extrapolated to over 488,000 wells in the 2009 emissions inventory (IHS CERA, 2011).

With an emerging topic like shale energy development, however, the impact of EPA's revised estimates was enormous. Emission estimates from production using EPA's figures were used to question the overall environmental benefits of natural gas. They were cited widely by unconventional gas opponents - many of whom used the new figures selectively and without caveats like "estimated" to argue against further development of shale energy resources. For example, an article published by ProPublica cited the revised EPA emission factors as "new research" which "casts doubt" on whether natural gas contributes lower GHG emissions than other fossil fuels (Lustgarten, 2011). Many of these studies – e.g., the work of Howarth *et al.* were widely reported in the popular press (Zellers, 2011) with little attention to the quality of analysis behind their conclusions.

Notably, other authors using more robust and defensible scientific methodologies argued that - even with undoubtedly high emissions estimates - natural gas still possessed a lifecycle advantage when its comparative efficiency in electricity generation was taken into account. For example, a study by Argonne National Laboratory utilizing the same EPA data sources concluded that taking into account power plant efficiencies, electricity from natural gas shows significant life-cycle GHG benefits over coal power plants (Burnham, 2011). Unfortunately, the complex technical arguments in these studies generated considerably less media and public attention.

It is important to understand that the ongoing debate about the accuracy of EPA's adjusted emission factor as contained in the 2009 inventory did not keep these numbers from being used in a series of rules that have wide ranging ramifications on national natural gas policies both in the United States and globally. Many countries considering shale energy development remain bound by the emissions reduction targets in the Kyoto Protocol and their regulatory discussions reflect greenhouse gas concerns. In addition to the very real risk that other countries could adopt the emission factor before the EPA can refine its calculations, the possibility of higher emissions (even if only on paper) might deter other nations from developing their own unconventional energy resources.

By the summer of 2011, it was clear to ANGA/API members (also referred to as API/ANGA members) that gathering additional data about actual emissions and points of uncertainty during unconventional gas production was essential to improve GHG life cycle analysis (LCA) of natural gas for the following reasons: 1) to focus the discussion of emissions from natural gas production around real data; 2) to promote future measurement and mitigation of emissions from natural gas production; and 3) to contribute to improving the emission estimation methods used by EPA for the natural gas sector in their annual national GHG inventory.

1.2 Introduction to the API/ANGA Survey

API and ANGA members uniformly believed that EPA's current GHG emissions estimates for the natural gas production sector were overstated due to erroneous activity data in several key areas - including liquids unloading, well re-fracturing, centrifugal compressors, and pneumatic controllers. Members therefore worked cooperatively to gather information through two data requests tailored to focus on these areas and reasonably accessible information about industry activities and practices. Specifically, information was requested on gas well types, gas well venting/flaring from completions, workovers, and liquids unloading, and the use of centrifugal compressor and pneumatic controllers.

The actual data requests sent to members can be found in Appendix A, and Appendix B provides more detailed data from the ANGA/API well survey information.

Survey results and summaries of observations, including comparisons to EPA's emission estimation methods, are provided in the following sections.

2. Well Data

This section examines well data gathered by API and ANGA members. Overall, ANGA/API's survey effort gathered activity data from over 20 companies covering nearly 91,000 wells and 19 of the 21 American Association of Petroleum Geologists (AAPG) basins[3] containing over 1% of the total well count in EPA's database of gas wells. Members believe that the API/ANGA survey represents the most comprehensive data set ever compiled for natural gas operations and, as such, provides a much more accurate picture of operations and emissions.

Information to characterize natural gas producing wells was collected by survey in two parts:

- The first part of the survey requested high-level information on the total number of operating gas wells, the number of gas well completions, and the number of gas well workovers with hydraulic fracturing. Data on over 91,000 wells was collected primarily for 2010, with some information provided for the first half of 2011.
- The second part of the survey requested more detailed well information about key activities. The well information collected through the two surveys is provided in Appendix B.

Section 2.1 looks at overall natural gas well counts, Section 2.2 examines completion data from ANGA/API members, and Section 2.3 briefly identifies several unresolved issues concerning well counts and classifications that could benefit from future analysis for examination. For the purposes of this report, unconventional wells are considered to be shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically.

2.1 National Gas Well Counts

To provide context for the information collected by API and ANGA, comparisons were made to information about national gas wells from EPA and the U.S. Energy Information Administration (EIA). Unfortunately, the government lacks a single coordinated and cohesive set of estimates for gas wells.

Industry grew concerned when it became apparent that significant discrepancies existed among different sources of national gas well data. The EPA inventory, the EIA, and IHS all reported different well counts that do not consistently distinguish between key areas like conventional and unconventional wells. Furthermore, there does not appear to be a single technical description for classifying wells that is widely accepted. Without consistent measures and definitions for the quantity and type of wells, it is difficult to reach agreement on the number of unconventional wells completed annually - let alone their emissions.

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[3] Basins are defined by the American Association of Petroleum Geologists (AAPG) AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978.

Both the EIA data and the EPA data accompanying the national GHG inventory lack sufficient detail for well classifications to provide a basis for helpful comparison with the survey data reported here. Instead, national well data developed as part of mandatory emissions reporting is used for comparison because it has the most appropriate level of detail in well categories (EPA, 2011d).

In EPA's database gas well count (EPA, 2011d), 21 of the AAPG basins each have more than 1% of the total well count. The API/ANGA survey has wells from 19 of those 21 basins. In terms of wells represented by these basins, 92% of the total EPA database well count is accounted for by wells in those 21 basins, while 95% of the ANGA/API surveyed gas wells are accounted for by those 21 basins. These results are summarized in Table 1 and illustrated in Figure 1. This indicates that the API/ANGA survey results have good representation for the basins with the largest numbers of wells nationally.

TABLE 1. COMPARISON OF GAS WELL COUNT DATA BY AAPG BASIN: SUMMARY STATISTICS

	EPA Database Gas Well Count*	API/ANGA Survey Data	ANGA/API as a % of EPA
Total number of U.S. gas wells	355,082 gas wells	91,028 gas wells	26%
Number of significant AAPG basins**	21 basins	Data on wells in 19 of those 21 basins	90%
Number of wells in significant AAPG basins	325,338 wells	86,759 wells	27%
% of total wells in significant AAPG basins	92%	95%	

[*] EPA's database gas well count (EPA, 2011d) differs from the well count provided in EPA's 2010 national inventory, but provides more detail on the types of wells. Additional details are provided in Appendix B.

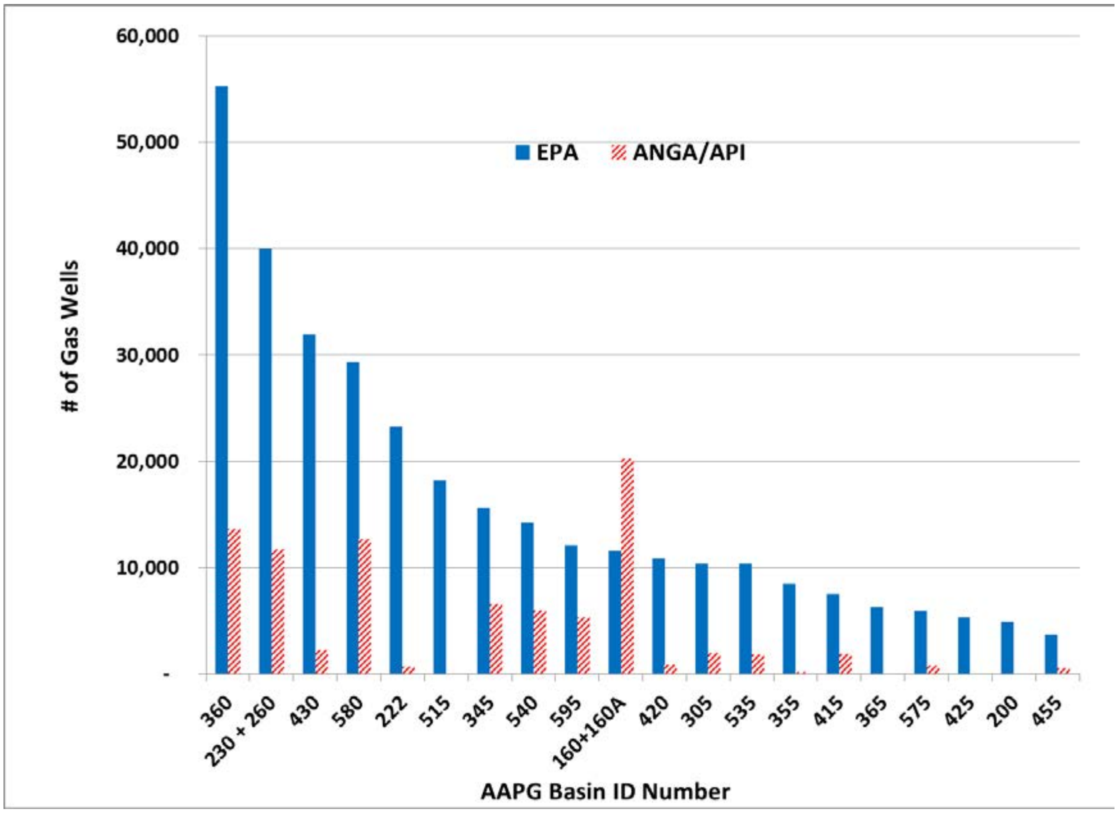
[**] Significant basins are defined as basins with more than 1% of the total national gas wells.

As shown in Figure 1, the API/ANGA survey results more heavily represent gas wells in specific AAPG basins when compared to EPA's basin-level well counts (EPA, 2011c). Unlike the EPA data, the ANGA/API data is more heavily influenced by AAPG 160 and 160A. AAPG basins 360, 230, and 580 are important for both data sets.

The smaller data set provided by EPA (2011d) may not include all of the Marcellus shale wells (particularly in Pennsylvania), and the well classification system used in this smaller data set could probably be made more rigorous. Although this comparison may not show a perfect distributional match for the basin by basin distribution of the API/ANGA survey data presented here, it does not change the fundamental conclusion of the ANGA/API survey since this data set does cover 90% of the basins and 27% of the national gas well count for the significant basins as reported by EPA (EPA, 2011d). The data discussed in this report provides substantial new information for understanding the emissions from Natural Gas Systems and offers a compelling justification for re-examining the current emission estimates for unconventional gas wells.

Appendix B contains more detail about the industry well data sample compared to the overall data maintained by the government. Unless otherwise noted, further statistical comparisons of well data throughout this paper are done with reference to the EPA data because it was the only one which effectively parsed the data by well type (EPA, 2011d).

FIGURE 1. COMPARISON OF EPA TO API/ANGA GAS WELL COUNT DATA BY AAPG BASIN



2.2 Gas Well Completions

Acknowledging the somewhat different time periods covered, the API/ANGA survey data represents 57.5% of the national data for tight gas well completions and 44.5% of shale gas well completions, but only 7.5% of the national conventional well completions and 1.5% of coal-bed methane well completions. About one-third of the surveyed well completions (2,205) could not be classified into the well types requested (i.e., tight, shale, or coal-bed methane). The survey results for well completions are provided in Table 2 and compared to national data provided to ANGA by IHS.[4]

EPA's 2010 inventory showed 4,169 gas well completions with hydraulic fracturing (EPA, 2012, Table A-122); however, EPA does not provide a breakout of completions by well type (shale gas, tight gas or coal-bed methane). In comparing the EPA 2010 count of gas well completions with hydraulic fracturing (4,169 completions) to both the survey results and data

[4] Data provided in e-mail from Mary Barcella (IHS) to Sara Banaszak (ANGA) on August 29,2011. Data were pulled from current IHS well database and represent calendar year 2009 (2010 data are not yet available).

provided by IHS, it seems that EPA's national GHG inventory underestimates the number of well completions. Even accounting for the difference in time periods (2010 for EPA compared to 2010/2011 data from the ANGA/API survey), the national inventory appears to under-represent the number of well completions.

TABLE 2. API/ANGA SURVEY – SUMMARY OF GAS WELL COMPLETIONS BY NEMS REGION AND WELL TYPE*
(FIRST SURVEY DATA REQUEST PHASE)

NEMS Region	Conventional Wells	Shale	Coal-bed Methane	Tight	Unspecified	Regional Total
API/ANGA Survey Data Gas Well Completions						
Northeast	2	291	3	67	126	489
Gulf Coast	81	588	-	763	374	1,806
Mid-Continent	22	734	-	375	270	1,401
Southwest	425	442	-	346	310	1,523
Rocky Mountain	10		30	977		1,017
Unspecified	-	-	-	-	1,125	1,125
Survey TOTAL	540	2,055	33	2,528	2,205	7,361
% of Survey Total	7.3%	27.9%	0.4%	34.3%	30.0%	
2010 IHS Gas Well Completions						IHS Total
2010 National Well Completions (from IHS)[1]	7,178	4,620	2,254	4,400		18,452
	38.9%	25.0%	12.2%	23.8%		
API/ANGA as % of IHS National Well Counts	7.5%	44.5%	1.5%	57.5%		

* ANGA/API survey data represents well counts current for calendar year 2010 or the first half of 2011.

** EPA's national GHG inventory does not designate gas wells by classifications of "shale", "coal bed methane" or "tight".

As shown in Table 3, the ANGA/API survey noted 7,361 gas well completions for 2010 and the first half of 2011. This is equivalent to approximately 40% of the gas well completions reported by IHS for 2010. Although EPA's 2010 national GHG inventory appears to under-represent the number of gas well completions according to the numbers reported through both the API/ANGA data and the IHS, differences in national well data reporting systems make it difficult to accurately investigate well completion differences with certainty. The EPA inventory, which uses data from HPDI, and the Energy Information Administration (in addition to privately sourced data) - all of which report different well counts that do not consistently distinguish between conventional and unconventional wells. Without a consistent measure for the quantity and type of wells, it is difficult to be confident of the accuracy of how many wells are completed annually, let alone to estimate their emissions. Industry strongly believes that the effects of any current under-representation of well completions will be offset by a more realistic emission factor for the rate of emissions per well.

TABLE 3. SUMMARY OF GAS WELL COMPLETIONS DATA (FIRST SURVEY DATA REQUEST PHASE)

	# Completions for Gas Wells without hydraulic fracturing	# Completions for Gas Wells with hydraulic fracturing	Total Completions
2010 National Well Completions (from EPA; EPA 2012)	702	4,169	4,871
% of National Total	14%	86%	
API/ANGA Survey Well Completions	540	6,821	7,361
% of National Total	7%	93%	
Well Completions from IHS	7,178	11,274	18,452
% of National Total	39%	61%	

Table 4 provides detailed data for well completions from the ANGA/API survey. From the survey, 94% of gas well completions in 2010 and the first half of 2011, were conducted on wells with hydraulic fracturing. About one-half of all gas well completions for this time period were for tight wells, and about one-half of all gas well completions were for vertical wells with hydraulic fracturing. Any differences in totals between Tables 2, 3 and 4 are because these tables were derived from the two different data requests sent to member companies as described previously in the introduction to Section 2.

TABLE 4. API/ANGA SURVEY – ADDITIONAL DETAILS ON GAS WELL COMPLETIONS (SECOND SURVEY DATA REQUEST PHASE)

	# Completions for Gas Wells with hydraulic fracturing (HF)				Gas Wells without hydraulic fracturing		Total Completions
	# Vertical wells completions	# Horizontal well completions	Total Wells with HF	% of Wells with HF	# Completions	% of Wells without HF	
TOTAL Conventional	315	57	372	69%	164	31%	536
TOTAL Shale	317	1,863	2,180	99%	30	1%	2,210
TOTAL Tight	2,054	368	2,422	96%	106	4%	2,528
TOTAL Coal Bed Methane	27	3	30	91%	3	9%	33
TOTAL OVERALL	**2,713**	**2,291**	**5,004**	**94%**	**303**	**6%**	**5,307**

The following points summarize survey information provided in Tables 2, 3 and 4. These tables represent a snapshot of well activity data during this time.

- Overall, the survey showed 94% of the 5,307 wells reported in the API/ANGA data set as completed in 2010 and the first half of 2011 used hydraulic fracturing.
- *536 conventional gas wells were completed in 2010 and the first half 2011.*
  - 59% were vertical wells with hydraulic fracturing,
  - 11% were horizontal wells with hydraulic fracturing, and
  - 31% were wells without hydraulic fracturing.
- *2,210 shale gas wells were completed in 2010 and the first half 2011.*
  - 14% were vertical wells with hydraulic fracturing,
  - 84% were horizontal wells with hydraulic fracturing, and
  - 1% were wells without hydraulic fracturing.
- *2,528 tight gas wells were completed in 2010 and the first half 2011.*
  - 81% were vertical wells with hydraulic fracturing,
  - 15% were horizontal wells with hydraulic fracturing, and
  - 4% were wells without hydraulic fracturing.
- *33 coal-bed methane wells were completed in 2010 and the first half 2011.*
  - 82% were vertical wells with hydraulic fracturing,
  - 9% were horizontal wells with hydraulic fracturing, and
  - 9% were wells without hydraulic fracturing.

2.3 Data Limitations Concerning Wells

In response to follow-up questions on well data, EPA indicated that they classified gas well formations into four types (conventional, tight, shale, and coal-bed) (EPA, 2011d). When developing the gas well classifications, EPA applied their judgment where data were not available in the database. ANGA and API are interested in using the well database compiled by IHS or a similar database, to more completely classify gas wells at some point in the future. The API/ANGA survey did not specifically define conventional wells for collecting the well data presented in this section, leaving the respondents to determine the classification of wells based on their knowledge of the well characteristics or state classifications. As such, this well classification may vary somewhat according to the respondent's classification of wells.

It should be noted that there is not a generally accepted definition for "gas wells." Producers might be producing from several zones in the same formation, and different states define "gas" or "oil" wells differently due to the historical structure of royalties and revenues. There is also no commonly used definition of "conventional" gas wells. Thus, different definitions of these terms may have produced inconsistency in the classification of wells between gas and oil, and conventional and unconventional for the surveyed results, as well as for the EPA and EIA national data. For the purposes of this report, unconventional wells are considered to be shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically.

3. Gas Well Liquids Unloading

Gas well clean ups also known as liquids unloading accounts for 51% of total CH_4 emissions from the natural gas production sector in EPA's national GHG inventory (EPA, 2012).[5] This was a considerable increase from the 6% of CH_4 emissions that liquids unloading represented in the 2008 inventory. The accuracy of assumptions regarding this activity was therefore a major concern to API/ANGA members.

As the name indicates, liquids unloading is a technique to remove water and other liquids from the wellbore so as to improve the flow of natural gas in conventional wells and unconventional wells.

In EPA's national inventory, emissions from gas well liquids unloading are based on the following assumptions:

- 41.3% of conventional wells require liquids unloading.
- 150,000 plunger lifts are in service, which equates to 42% of gas wells.
- The average gas well is blown down to the atmosphere 38.73 times per year.
- The average casing diameter is 5 inches.
- A gas well is vented to the atmosphere for 3 hours once the liquids are cleared from the well.

The ANGA/API survey gathered activity and emissions related information for gas well liquids unloading. Information was received covering eight conventional well data sets and 26 unconventional well data sets. The following information was requested:

- Geographic area represented by the information provided;
- Time period – data were annualized to 12 months if the information was provided for a partial year;
- Number of operated gas wells represented by the information provided;
- Number of gas wells with plunger lift installed;
- Number of gas wells with other artificial lift (beam pump; ESP; etc.);
- Total number of gas well vents;
- Number of wells with and without plunger lifts that vent to the atmosphere;
- Total count of gas well vents for time period with and without plunger lifts;
- Average venting time for wells with and without plunger lifts;
- Average daily production of venting gas wells (Mcf/day);
- Average depth of venting wells (feet);

[5] See EPA Table A-129, of Annex 3 of the 2010 inventory report.

- Average casing diameter of venting gas wells (inches);
- Average tubing diameter of venting gas wells with plunger lift (inches); and
- Average surface pressure - venting gas wells (psig).

Table 5 summarizes the results from the API/ANGA survey and compares the results to the assumptions EPA uses to estimate emissions for this source in the national GHG inventory.

The ANGA/API data differed from EPA's assumptions in several ways:

1) API/ANGA showed lower percentages of wells with plunger lifts;
2) API/ANGA data indicated lower percentages of wells venting to the atmosphere;
3) API/ANGA data showed lower average vent times than EPA's numbers; and
4) Casing diameters from the API/ANGA survey were comparable to EPA's assumption of 5 inches.

TABLE 5. ANGA/API SURVEY – SUMMARY OF LIQUIDS UNLOADING DATA

	API/ANGA Survey		
Parameter	**Conventional Wells**	**Unconventional Wells**	**EPA Assumptions**
Number of gas wells with plunger lifts	10%	45%	42%
Number of gas wells with other artificial lift (beam pump, ESP, etc.)	25%	7%	
Number of gas wells vented to the atmosphere for liquids unloading	11%	16%	41.3%
# vents per well (weighted average)	303.9 (all data)*	33.6	38.7
	32.4 (w/o outliers) **		
Average venting time per vent (weighted average)			
With plunger lifts	0.25 hours	0.77 hours	3 hours
Without plunger lifts	1.78 hours	1.48 hours	
Weighted Average casing diameter	4.64 inches	5.17 inches	5 inches
Weighted Average tubing diameter	2.27 inches	2.43 inches	
Average Emission factor, Mscf/well			
With plunger lifts	823 (all data)*	196	
	14.7 (w/o outliers)**		
Without plunger lifts	56.4	318	
Weighted average Methane emission factor, Mscf CH4/well	175*		1,316

* Includes all liquids unloading data from the ANGA/API survey

** Excluding two high data points

When examining Table 5, it is important to note the presence of several outliers. Two data responses for operations with conventional wells reported very high frequencies of vents to the atmosphere. These data sets represent 174 gas wells with plunger lifts (out of a total 788 gas wells with plunger lifts represented by the total data set) located in the Mid-Continent region. The wells represented by these data points have plunger lifts that vent to the atmosphere for each plunger cycle. The information was confirmed by the two data respondents and is an artifact of the plunger control for these wells which results in very short venting durations (between 4 and 5 minutes) for each plunger cycle. As a result, accounting for the high frequency of plunger lift cycles for these wells results in a high average vent frequency, but still produces a lower emission factor than the EPA assumptions.

Excluding these two data points, the API/ANGA survey data for the number of vents per well was comparable to EPA's assumed frequency. Moreover, even with the high frequency of vents from these wells, the emissions are much lower than EPA's estimates (see Table 6).

TABLE 6. ANGA/API SURVEY –LIQUIDS UNLOADING EMISSIONS COMPARISON

	API/ANGA Survey		EPA Inventory			API & ANGA - EPA EPA
NEMS Region	Emission Factor, Mscf CH4/well	Estimated Emissions, tonnes CH_4	# wells	Emission Factor, Mscf CH_4/well	Estimated Emissions, tonnes CH_4 *	% Difference in Emissions
Northeast	136	202,503	77,931	1,360	2,027,265	-90%
Mid Continent	392	235,813	31,427	703	422,893	-44%
Rocky Mountain	177	90,387	26,620	690	351,672	-74%
Southwest	36	7,913	11,444	865	189,407	-96%
Gulf Coast	169	101,150	31,331	2,519	1,510,259	-93%
West Coast	No data for this region		638	1,492	Excluded for consistent comparison	
TOTAL	175 (weighted average)	637,766	179,391		4,501,465	-86%

*EPA estimated emissions = # wells × EPA emission factor, converted to mass emissions based on 60 degrees F and 14.7 psia

These variances among operators in ANGA/API data demonstrate the challenge of applying national emissions estimates to conditions in which there can be considerable variation in wells and operating techniques, among and even within various regions. As member companies have noted in various comments to regulators, oil and natural gas production operations vary considerably according to factors such as local geology, hydrology, and state law.

EPA noted that wells equipped with plunger lifts have approximately 60% lower emissions from liquids unloading than wells without plunger lifts (EPA, 2011b). From the API/ANGA survey, an emission reduction of about 38% was observed for the unconventional wells equipped with plunger lifts compared to those without plunger lifts. However, Table 5 indicates that for conventional gas wells, the average emission factor is higher for wells with plunger lifts compared to those without when the two high data points are included. Excluding the two high data points, the emission factor for conventional wells with plunger lifts is 74% lower than the emission factor for conventional wells without plunger lifts.

One reason for this discrepancy in the data may be that EPA has acknowledged that their current estimation method for liquids unloading does not account for activities used to reduce CH_4 emissions by many different artificial lift methods used in industry. According to Natural Gas Star Reports, the applicable emission reductions range from 4,700 to 18,250 Mscf/yr for plunger lift systems (EPA, 2006); however, since the emission reductions are reported separate from the emission estimate in the national inventory, they cannot be linked back to EPA emission source categories.

Emissions were calculated by applying Equation W-8 or W-9 from the EPA GHG reporting rule in 40 CFR 98 Subpart W, where Equation W-8 applies to gas wells without plunger lifts, and Equation W-9 applies to gas wells with plunger lifts. Appendix C summarizes the data collected and estimated emissions. The emission results are shown in Table 6 by NEMS region for comparison to EPA's emission estimates. The ANGA/API survey averaged the emission factors data within each NEMS region for conventional and unconventional wells combined. The emission results shown in Table 6 were determined by applying the API/ANGA emission factors and EPA emission factors, respectively, to the total number of wells requiring liquids unloading from the 2010 national GHG inventory.

As production companies continue to collect information for EPA's mandatory GHG reporting program, better information on liquids unloading frequency and emissions will be available. One area that would benefit from additional information is an investigation of regional differences, or plunger lift control practices, in view of the high frequency of vents observed for two data sets containing conventional gas wells with plunger lifts in the Mid-Continent region.

Key findings of the ANGA/API survey on liquids unloading are:

- ***For all of the NEMS regions, the API/ANGA survey data resulted in lower emission estimates than EPA estimated for the 2010 national GHG inventory when compared on a consistent basis.***
- ***Overall, the change in emission factors based on data collected from the ANGA/API survey reduces estimated emissions for this source by 86% from the emissions reported in EPA's 2010 national GHG inventory.***

4. Hydraulic Fracturing and Re-fracturing (Workovers)

A well workover refers to remedial operations on producing natural gas wells to try to increase production. Starting with the 2009 inventory, EPA split the estimation of emissions from producing gas wells into conventional (i.e., without hydraulic fracturing) and unconventional (i.e., with hydraulic fracturing). For workovers of wells without hydraulic fracturing, the 2009 and 2010 national inventories used emission factors of the same order of magnitude as the 2008 inventory (2,454 scf of CH_4/workover). In contrast, the unconventional (with hydraulic fracturing) well workover emission factor increased by a factor of three thousand (3,000).

EPA did acknowledge that the new emission factor for well workovers was based on limited information (EPA, 2011a). Moreover, several publications including *Mismeasuring Methane* by IHS CERA underscored the perils of extrapolating estimates using only four (4) data points representing approximately two percent (2%) of wells – particularly when the data was submitted in the context of the Natural Gas Star program, which was designed to highlight emissions reduction options (IHS CERA, 2011). Unfortunately, even if the EPA's workover factor is high, it must be used in estimated emissions calculations until it is officially changed.

EPA's new emission factor is 9.175 MMscf of natural gas per re-fracture (equivalent to 7.623 MMscf CH_4/re-fracture). Additionally, EPA used this new emission factor in conjunction with an assumed re-fracture rate of 10% for unconventional gas well workovers each year to arrive at their GHG emission estimate for this particular category.

4.1 API/ANGA Survey

The ANGA/API survey requested counts for gas well workovers or re-fractures in two separate phases of the survey, covering 91,028 total gas wells (Table 7 covering 2010 and first half of 2011 data) and 69,034 unconventional gas wells (Table 8, 2010 data only), respectively.

The first phase of the survey was part of the general well data request. Counts of workovers by well type (conventional, tight, shale, and coal bed methane) and by AAPG basin were requested. The frequency of workovers was calculated by dividing the reported workover rates by the reported total number of each type of gas well. These results are summarized in Table 7, which includes a comparison to national workover data from EPA's annual GHG inventory. The high number of workovers in the Rocky Mountain region is discussed further below.

Table 7 indicates that even for the high workover rates associated with unconventional tight gas wells, the workover rate is much less than EPA's assumed 10% of gas wells re-fractured each year. Based on this first phase of the survey,

- The overall workover rate involving hydraulic fracturing was 1.6%.
- However, many of these workovers were in a single area, AAPG-540, where workovers are known to be conducted more routinely than in the rest of the country (as described in more detail below Table 8). Excluding AAPG 540, the overall workover rate involving hydraulic fracturing was 0.7%

- For all unconventional wells in Table 7, the overall workover rate involving hydraulic fracturing was 2.2%. Excluding AAPG 540, the overall workover rate involving hydraulic fracturing was 0.9%.

Table 7. API/ANGA Survey – Summary of Gas Well Workovers with Hydraulic Fracturing in 2010 and First Half of 2011 by NEMS Region and Well Type (First Phase Data Survey)

<table>
<tr><th rowspan="2">NEMS Region</th><th rowspan="2">Conventional Wells</th><th colspan="4">Unconventional Wells</th></tr>
<tr><th>Shale</th><th>Coal-bed Methane</th><th>Tight</th><th>Unspecified</th></tr>
<tr><td>Northeast</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Gulf Coast</td><td>-</td><td>5</td><td>-</td><td>38</td><td>73</td></tr>
<tr><td>Mid-Continent</td><td>8</td><td>1</td><td>-</td><td>73</td><td>33</td></tr>
<tr><td>Southwest</td><td>60</td><td>25</td><td>-</td><td>8</td><td>7</td></tr>
<tr><td>Rocky Mountain</td><td>4</td><td>-</td><td>25</td><td>901</td><td>-</td></tr>
<tr><td>West Coast</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Unspecified</td><td>-</td><td>-</td><td>-</td><td>-</td><td>200</td></tr>
<tr><td rowspan="2">Survey TOTAL</td><td rowspan="2">72</td><td>31</td><td>25</td><td>1,020</td><td rowspan="2">313</td></tr>
<tr><td colspan="3">1,076</td></tr>
<tr><td>% of national</td><td>0.3%</td><td colspan="3">21.3%</td><td></td></tr>
<tr><td>Overall Survey Total
% of national</td><td colspan="5">1,461
5.6%</td></tr>
</table>

<table>
<tr><td rowspan="4">National Workover Counts (from EPA's 2010 national inventory)</td><td>Conventional Wells</td><td>Unconventional Wells</td></tr>
<tr><td>21,088</td><td>5,044</td></tr>
<tr><td>80.7%</td><td>19.3%</td></tr>
<tr><td colspan="2">26,132</td></tr>
</table>

<table>
<tr><th rowspan="2"></th><th rowspan="2">Conventional Wells</th><th colspan="4">Unconventional Wells</th></tr>
<tr><th>Shale</th><th>Coal-bed Methane</th><th>Tight</th><th>Unspecified</th></tr>
<tr><td>% Workover Rate with Hydraulic Fracturing (from ANGA/API Survey)</td><td>0.3%</td><td>0.3%</td><td>0.5%</td><td>3.0%</td><td>2.4%</td></tr>
<tr><td>Tight w/out AAPG 540</td><td rowspan="3"></td><td></td><td></td><td>0.5%</td><td></td></tr>
<tr><td>Unconventional Wells</td><td colspan="4">2.2%</td></tr>
<tr><td>W/out AAPG 540</td><td colspan="4">0.9%</td></tr>
<tr><td>All Wells</td><td colspan="5">1.6%</td></tr>
<tr><td>All Wells w/out AAPG 540</td><td colspan="5">0.7%</td></tr>
</table>

Also, the ANGA/API survey collected information on the number of workovers for vertical and horizontal unconventional gas wells. Nearly 99% of the unconventional gas well workovers were on vertical wells. Additionally, 18% of the gas well workovers from the API/ANGA survey were conducted on gas wells without hydraulic fracturing.

A second phase of the survey was conducted which targeted collecting gas well re-fracture information for 2010 to provide a better estimate than EPA's assumption that 10% of wells are re-fractured each year. This portion of the ANGA/API survey requested information just for "unconventional" gas wells (i.e., those located on shale, coal-bed methane, and tight formation reservoirs), where the formations require fracture stimulation to economically produce gas. A re-fracture or workover was defined for this second phase of the survey as a re-completion to a different zone in an existing well or a re-stimulation of the same zone in an existing well. These results are summarized in Table 8.

While there likely is significant overlap of unconventional well data reported in the first and second phases of the survey (which covered over 62,500 unconventional wells and 69,000 unconventional wells respectively), combined these data indicate an unconventional well re-fracture rate of 1.6% to 2.3% including AAPG 540 and 0.7% to 1.15% excluding AAPG 540.

AAPG Basin 540 (i.e. DJ Basin) which is part of the Rocky Mountain Region stands out in Tables 7 and 8. After four (4) to eight (8) years of normal production decline, the gas wells in this basin can be re-fractured in the same formation and returned to near original production. Success of the re-fracture program in the DJ Basin is uniquely related to the geology of the formation, fracture reorientation, fracture extension and the ability to increase fracture complexity. Also, most DJ Basin gas wells are vertical or directional, which facilitates the ability to execute re-fracture operations successfully and economically. These characteristics result in a high re-fracture or workover rate specific to this formation.

ANGA and API believe the high re-fracture rate observed in the DJ Basin is unique and not replicated in other parts of the country. There may be a few other formations in the world that have similar performance, but the successful re-fracture rate in the DJ Basin is not going to be applicable to every asset/formation and there is no evidence of the high re-fracture rate in any of the other 22 AAPGs covered in the API/ANGA survey. It is highly dependent on the type of rock, depositional systems, permeability, etc. For these reasons, re-fracture rates for tight gas wells and all gas wells with and without AAPG Basin 540 are summarized in Tables 7 and 8.

TABLE 8. API/ANGA SURVEY – SUMMARY OF 2010 GAS WELL WORKOVERS ON UNCONVENTIONAL WELLS BY AAPG BASIN AND NEMS REGION (SECOND PHASE SURVEY DATA)

NEMS Region	AAPG	Number of Unconventional Operating Gas Wells	Number of Hydraulic Fracture Workovers on Previously Fracture Stimulated Wells	% Wells re-fractured per year	Regional % Wells re-fractured per year
Northeast	160	1,976	0	0.00%	0%
	160A	760	0	0.00%	
Gulf Coast	200	2	0	0.00%	0.91%
	220	649	2	0.31%	
	222	629	3	0.48%	
	230	820	4	0.49%	
	250	13	0	0.00%	
	260	2,830	36	1.27%	
Mid-Continent	345	3,296	11	0.33%	0.95%
	350	213	3	1.41%	
	355	282	8	2.84%	
	360	7,870	89	1.13%	
	375	12	0	0.00%	
	385	1	0	0.00%	
	400	64	0	0.00%	
Southwest	415	1,834	0	0.00%	1.04%
	420	838	8	0.95%	
	430	1,548	36	2.33%	
	435	2	0	0.00%	
Rocky Mountain	515	1	0	0.00%	4.7%
	540	5,950	866	14.55%	
	580	8,197	8	0.10%	
	595	5,222	32	0.61%	
Not specified		26,025	487	1.87%	1.87%
Unconventional TOTAL (all wells)		**69,034**	**1,593**	**2.31%**	
Unconventional Median		790	3		
Rocky Mountain Region Unconventional Total		19,370	906	4.68%	
Unconventional TOTAL (Without AAPG 540)		63,084	727	1.15%	

4.2 WRAP Survey

Other information on re-fracture rates is available in a survey conducted by the Western Regional Air Partnership (WRAP). WRAP conducted a survey of production operators in the Rocky Mountain Region (Henderer, 2011) as part of the initiative to develop GHG reporting guidelines for a regional GHG cap and trade program.

Within each basin in this region, the top oil and gas producers were identified and invited to participate in the survey. The goal was to have operator participation that represented 80% of the production for the region. The spreadsheet survey requested information on the completions, workovers, and emissions associated with these activities. An emission factor and frequency of re-fracturing was developed for each basin as a weighted average of the operator responses.

The re-fracture rates from the WRAP survey are shown in Table 9 (Henderer, 2011).

TABLE 9. WRAP SURVEY – SUMMARY OF GAS WELL WORKOVERS BY AAPG BASIN FOR THE ROCKY MOUNTAIN REGION, 2006 DATA

AAPG Basin	# Wells represented by survey	# Wells Recompleted	% Recompleted
515	4,484	121	2.70%
530	731	5	0.68%
535	4,982	201	4.03%
540	8,247	636	7.71%
580	3,475	14	0.40%
595	4,733	275	5.81%
Total	26,652	1,252	
Weighted average			4.70%

AAPG Basin 540 results in the highest re-fracture rate for this data set, consistent with the ANGA/API survey as noted above. It is noteworthy that, while there are differences among individual AAPG Basin results, the weighted average re-fracture rate from the WRAP survey in 2006 is the same as the Rocky Mountain regional 4.7% re-fracture rate from the API/ANGA survey shown in Table 8.

4.3 Impact of Completions and Re-fracture Rate Assumptions

Table 10 compares the considerable reduction in the national GHG inventory that would result from applying a lower re-fracture rate.

EPA indicated that the national inventory assumes 10% of unconventional gas wells are re-fractured each year. Table 10 replaces this value with results from the ANGA/API survey. A re-fracture rate of 1.15% is applied to unconventional gas wells in the Mid-Continent and Southwest regions (No unconventional gas wells were assigned to the Northeast and Gulf Coast regions. The West Coast region is not shown since the API/ANGA survey did not include any responses for gas well operations in this region.) A re-fracture rate of 4.7% is applied to unconventional gas wells in the Rocky Mountain region.

With these adjustments to the re-fracture rate for unconventional gas wells, the national emission estimate is reduced by 72% for this emission source category, from 712,605 metric tons of CH_4 to 197,311 metric tons of CH_4 when compared on a consistent basis.

4.4 Completion and Re-fracture Emission Factor

In the 2009 GHG national inventory, EPA applies an emission factor of 2,454 scf CH_4/event for conventional gas well workovers, while the emission factor for unconventional gas well completions and workovers was increased to 7,623,000 scf CH_4/event (EPA, 2011b). Similarly, for the 2010 national GHG inventory, EPA maintained the emission factor of 2,454 scf CH_4/event for gas well workovers without hydraulic fracturing, but applied an average emission factor of 7,372,914 to gas well workovers with hydraulic fracturing (EPA, 2012). (EPA applies slightly different emission factors for each NEMS region based on differing gas compositions.)

The ANGA/API survey focused on activity data and did not collect data to revise the emission factor for unconventional gas well completions and workovers.

TABLE 10. API/ANGA SURVEY –GAS WELL WORKOVER EMISSIONS COMPARISON

NEMS Region	Well type	2010 EPA National Inventory # workover	Adjusted # workovers (based on API/ANGA survey)	2010 EPA National Inventory		Revised Emissions, tonnes CH_4 (based on ANGA/API survey)	API & ANGA - EPA EPA % Difference
				Emission Factor, scf CH_4/workover	Estimated Emissions, tonnes CH_4*		
Northeast	Wells without Hydraulic Fracturing	8,208	8,208	2,607	409	409	
	Wells with Hydraulic Fracturing	0	0	7,694,435	0	0	
Mid Continent	Wells without Hydraulic Fracturing	3,888	3,888	2,574	191	191	
	Wells with Hydraulic Fracturing	1,328	153	7,672,247	194,950	22,462**	-89%
Rocky Mountain	Wells without Hydraulic Fracturing	3,822	3,822	2,373	174	174	
	Wells with Hydraulic Fracturing	2,342	1,100	7,194,624	322,402	151,432**	-53%
Southwest	Wells without Hydraulic Fracturing	1,803	1,803	2,508	87	87	
	Wells with Hydraulic Fracturing	1,374	158	7,387,499	194,217	22,382**	-89%
Gulf Coast	Wells without Hydraulic Fracturing	3,300	3,300	2,755	174	174	
	Wells with Hydraulic Fracturing	0	0	8,127,942	0	0	
TOTAL					712,605	197,311	-72%

* EPA Estimated emissions = 2010 # Workovers x EPA 2010 Emission Factor, converted to mass emissions based on 60°F and 14.7 psia.

** Revised emissions = Adjusted # Workovers x Emission Factor, converted to mass emissions based on 60°F and 14.7 psia.

Emissions Data from WRAP Study

The WRAP study discussed in Section 4.2 also gathered data on emissions from completions. This information supports a revised emission factor but was reported by sources outside the ANGA/API data survey. The results are summarized in Table 11. The WRAP emission factor is 78% lower than EPA's emission factor (9.175 MMscf gas/event). The WRAP survey did not provide a methodology for determining emissions data.

TABLE 11. WRAP SURVEY – SUMMARY OF COMPLETION EMISSIONS FOR THE ROCKY MOUNTAIN REGION, 2006 DATA

AAPG Basin	Weighted average gas emissions from completion, Mcf gas/well	# completions represented
515	167	207
530	268	54
535	76	642
540	59	608
580	6,559	283
595	4,053	819
Total		2,613
Weighted average	2,032 Mcf/well	

4.5 Data Limitations for Completion and Re-fracture Emissions

Although the data sets are limited, it appears that EPA's assumed re-fracture rate of 10% is a significant overestimate. Information from the API/ANGA survey indicates that even including what appears to be unique activity in AAPG-540, the re-fracture rate is much less frequent, ranging from 1.6% to 2.3% based on two sets of survey information (Tables 7 and 8, respectively). The re-fracture rate for AAPG Basin 540 appears to be higher than other areas in the U.S. due to unique geologic characteristics in that region (4.7% based on a weighted average of data reported for that region). Without AAPG Basin 540, the national rate of re-fracturing is between 0.7% and 1.15% of all gas wells annually.

Additionally, limited information on the emissions from completions and workovers with hydraulic fracturing indicate that EPA's GHG emission factor for these activities is significantly overestimated. It is expected that better emissions data will develop as companies begin to collect information for EPA's mandatory GHG reporting program (EPA, 2011c).

5. Other Surveyed Information

EPA had indicated that activity data for centrifugal compressor wet seals and pneumatic devices used in the national inventory is lacking. Note that the need for better equipment data persists throughout the majority of the U.S. inventory and is not unique to the oil and natural gas industry. The ANGA/API survey requested the following information related to centrifugal compressors and pneumatic devices:

- The number of centrifugal compressors, reported separately for production/gathering versus processing;
- The number of centrifugal compressors with wet versus dry seals, reported separately for production/gathering versus processing;
- The number of pneumatic controllers, classified as "high-bleed," "low-bleed," and "intermittent," reported separately for well sites, gathering/compressor sites, and gas processing plants; and
- The corresponding number of well sites, gathering/compressor sites, and gas processing plants, associated with the pneumatic controller count.

5.1 Centrifugal Compressors

Processing Facilities

The API/ANGA survey collected the equivalent of 5% of the national centrifugal compressor count for gas processing operations (38 centrifugal compressors from the survey, compared to 811 from EPA's 2010 national GHG inventory). For the gas processing centrifugal compressors reported through the survey, 79% were dry seal compressors and 21% were wet seals. EPA's 2010 national inventory reported 20% of centrifugal compressors at gas processing plants were dry seal, and 80% were wet seal. EPA's emission factor for wet seals (51,370 scfd CH_4/compressor) is higher than the emission factor for dry seals (25,189 scfd CH_4/compressor).[6]

Based on the ANGA/API survey, EPA appears to be overestimating emissions from centrifugal compressors. If the small sample size from the API/ANGA survey is representative, non-combustion emissions from centrifugal compressors would be 173,887 metric tons of methane compared to 261,334 metric tons of methane from the 2010 national inventory (when applying industry standard conditions of 60 °F and 14.7 psia to convert volumetric emissions to mass emissions). Although based on very limited data, if the ANGA/API survey results reflect the population of wet seal versus dry seal centrifugal compressors, the emissions from this source would be reduced by 34% from EPA's emission estimate in the national inventory. Better data on the number of centrifugal compressors and seal types will be available from companies reporting to EPA under the mandatory GHG reporting program.

[6] EPA Table A-123, of Annex 3 of the 2010 inventory report.

Production and Gathering Facilities

Very few of the data sets reported through the API/ANGA survey indicate counts of centrifugal compressors associated with production/gathering operations - only 550 centrifugal compressors from 21 participating companies. EPA's 2010 GHG inventory did not include centrifugal compressors in production/gathering operations. On a well basis, the survey responses equate to 0.07 centrifugal compressors per gas well, with 81% dry seal centrifugal compressors and the remaining wet seal compressors. Information reported through EPA's mandatory GHG reporting program will provide additional information to account for GHG emissions from centrifugal compressors in production operations.

5.2 Pneumatic Controllers

Table 12 summarizes the survey responses for pneumatic controllers. For each type of location – gas well sites, gathering compressor sites, and gas processing plants – the count of the number of sites represented by the survey data is shown. Table 12 also shows the percent of each pneumatic controller type for each type of location.

TABLE 12. ANGA/API SURVEY –PNEUMATIC CONTROLLER COUNTS

	Gas Well Sites		Gathering/ Compressor Sites		Gas Processing Plants	
# wells, sites or plants	48,046 wells		1,988 sites		21 plants	
# controllers/well, site or plant	0.99 per well		8.6 per site		7.8 per plant	
# Low Bleed Controllers	12,850	27%	5,596	33%	117	71%
# High Bleed Controllers	11,188	24%	1,183	7%	47	29%
# Intermittent Controllers	23,501	49%	10,368	60%	0	0%

The survey requested that the responses designate pneumatic controllers as either "high bleed", "low bleed", or "intermittent" following the approach each company is using for Subpart W reporting. For example, Subpart W defines high-bleed pneumatic devices as automated, continuous bleed flow control devices powered by pressurized natural gas where part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour (EPA, 2011c).

EPA does not currently track pneumatic controllers by controller type in the national inventory. This information will be collected under 40 CFR 98 Subpart W starting in September 2012. From the API/ANGA survey, intermittent bleed controllers are the more prevalent type at gas well sites and gathering/compressor sites, while gas plants predominately use low-bleed controllers. No intermittent controllers were reported for gas plants by the survey respondents.

Table 13 compares emission results based on applying the emission factors from the EPA's GHG reporting rule to emissions presented in the 2010 national GHG inventory, using the counts of pneumatic controller from the ANGA/API survey for production operations.

For production, the EPA national inventory combines pneumatic controller counts associated with large compressor stations with pneumatic controllers in production. An emission factor for each NEMS region is applied to the count of total controllers in each NEMS region. For this comparison, a weighted average emission factor of 359 scfd CH_4/device was applied to the count of pneumatic controllers located at well sites and gathering/compressor sites.

Under the EPA mandatory reporting rule (40 CFR 98 Subpart W), separate emission factors are applied to pneumatic controllers based on the controller type and whether the controller is located in the Eastern or Western region of the United States, as specified in the rule (EPA, 2011c). For this comparison, an average of the eastern and western emission factors is applied to each device type in computing the emission estimates resulting from the EPA GHG reporting rule.

TABLE 13. PNEUMATIC CONTROLLER EMISSION COMPARISON – PRODUCTION OPERATIONS

	API/ANGA Survey Count of Controllers			EPA GHG Reporting Rule (Subpart W)		2010 National GHG Inventory	
	Gas Well Sites	Gathering/ Compressor Sites	Total	Emission Factor,* scfh CH_4/device	Emissions, tonnes CH_4/yr	Emission Factor, scfd CH_4/device	Emissions, tonnes CH_4/yr
# Low Bleed Controllers	12,850	5,596	18,446	1.58	4,885	359	46,286
# High Bleed Controllers	11,188	1,183	12,371	42.35	87,814		31,042
# Intermittent Controllers	23,501	10,368	33,869	15.3	86,856		84,987
Total			64,686		179,556		162,315

* Emission factors shown are the average of the eastern and western emission factors from Table W-1A (EPA, 2011c).

Based on the types of pneumatic controllers reported in the ANGA/API survey, EPA's mandatory GHG reporting rule could increase CH_4 emissions 11% over the pneumatic controller portion of the 2010 national GHG inventory. To put this in context, in EPA's inventory report for 2010, emissions from pneumatic controllers accounted for approximately 13% of CH_4 emissions from the natural gas field production stage. Any increase from that initially reported data, however, will likely represent a worst case scenario. It is important to remember that pneumatic controllers operate only intermittently, so variability such as the frequency and duration of the activations will be important information to consider when defining an accurate and effective reporting regime for these sources.

EPA's mandatory GHG reporting rule does not require reporting emissions from pneumatic controllers at gas processing plants, so no emission factors are specified. The GHG national inventory applies an emission factor of 164,721 scfy CH_4 per gas plant for pneumatic controllers. For the national inventory, this results in 1,856 tonnes CH_4 emissions - a very small contribution to CH_4 emissions from onshore oil and gas operations.

6. Conclusions

API and ANGA members believe this to be the most comprehensive set of natural gas data to date and are pleased to share these results with both regulators and the public.

Based on the information gathered from member companies during this project, it appears that EPA has overstated several aspects of GHG emissions from unconventional natural gas production. As summarized in Table 14, the ANGA/API survey data results in significantly lower emission estimates for liquids unloading and unconventional gas well refracturing when compared to EPA's emission estimates in the national inventory. Using the combined emission estimates from the survey for these two key emission sources would indicate a 50% reduction in calculated natural gas production sector emissions compared to EPA's estimates. This reduction would shift Natural Gas Systems from the largest to the second largest producer of methane emissions (approximately 123.4 MMT CO_2e in lieu of 215.4 MMT CO_2e), behind Enteric Fermentation (which is a consequence of bovine digestion, at 141.3 MMT CO_2e).

TABLE 14. EMISSION COMPARISON BETWEEN EPA AND INDUSTRY DATA

Source Category	EPA National Inventory		API/ANGA Survey		Impact on Source Category Emissions
	Metric tons of CH4	% of EPA Production Total	Metric tons of CH4	% of Revised Production Total	<u>API & ANGA - EPA</u> EPA % Difference in Emissions
Liquids Unloading	4,501,465 *	51%	637,766	14%	-86%
Unconventional Well Re-fracture Rates	712,605 *	8%	197,311	4%	-72%
Other Production Sector Emissions**	3,585,600	41%	3,585,600	81%	
Total Production Sector Emissions	8,799,670		4,420,677		-50%

* EPA's estimates are adjusted to industry standard conditions of 60 degrees F and 14.7 psia for comparison to the ANGA/API emission estimates.

**The "Other Production Sector Emissions" are comprised of over 30 different source categories detailed in Table A-129 in the Annex of the EPA's 2012 national inventory. The "Other Production Sector Emissions" are the same values for this comparison between the EPA national inventory and the API/ANGA survey to focus the comparison on quantified differences in emission estimates for gas well liquids unloading and unconventional well re-fracture rates.

This project was directed toward gathering more robust information on workovers, completions, liquids unloading, centrifugal compressors, and pneumatic controllers with the intent of supporting revisions to the activity factors used in EPA's national inventory and cited by many media publications. Although limited information was collected on centrifugal compressors and pneumatic controllers, the survey results indicated potential additional differences, which are not included in the Table 14 comparison, when comparing total emissions from all sources to the national inventory. Additional future data collection efforts, including more detailed reporting under Subpart W of the GHGRP will likely resolve these differences and continue to inform the overall natural gas emissions data.

In the meantime, however, while API and ANGA recognize that the data collected for this report represents a sample of the universe of natural gas wells operating in the U.S., we believe that the conclusions drawn from the data analysis are relevant and representative of natural gas production as whole. In EPA's gas well count, 21 of the AAPG basins each have more that 1% of the total well count. The ANGA/API survey has wells from 19 of those 21 basins. In terms of wells represented by these basins, 92% of the total EPA well count is accounted for by wells in those 21 basins, while 95% of the API/ANGA surveyed gas wells are accounted for by those 21 basins. This indicates that the ANGA/API survey results have good representation for the basins with the largest numbers of wells nationally.

Industry also believes that the systematic approach in which the API/ANGA data were collected and vetted by natural gas experts is an improvement over the *ad hoc* way in which EPA collected some of their data. This study indicates that EPA should reconsider their inventory methodologies for unconventional natural gas production particularly in light of more comprehensive and emerging data from the industry. ANGA and API members look forward to working with the agency to continue to educate and evaluate the latest data as it develops about the new and fast-changing area of unconventional well operations.

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Appendix A. API/ANGA Survey Forms

The following provides the survey forms used to gather data presented in this report.

FIGURE A-1. SURVEY INSTRUCTIONS

The attached worksheets request data to support both the API/ANGA Natural Gas Life Cycle Analysis Project, as well as updates to EPA's National GHG Inventory. Portions of this information are consistent with data required for Subpart W, in which case data collected for Subpart W can be provided.

EPA's most recent national inventory significantly increased the emission estimates for gas well completions and workovers with hydraulic fracturing and gas well liquids unloading. These increases prompted public criticism of unconventional natural gas production.
While acknowledging their unconventional well workover activity factors were based on limited data, EPA has also indicated that activity data for centrifugal compressor wet seals and pneumatic devices used in the national inventory is lacking.

API and ANGA are requesting this information to develop more rigorous emission estimates for these important emission sources. This spreadsheet primarily focuses on activity factor information. A second data request will be developed later this year to collect information to support improved emission factors.

Company confidential information will be protected.

Please do not send information responsive to the data request to API or ANGA. Neither API nor ANGA will review member data sent in response to this request. Any submission to API or ANGA that appears to contain information responsive to EPA's data request will be returned to the sender unopened.

Please send the completed spreadsheets to:
Terri_Shires@URScorp.com
Questions may be directed to the same address, or by phone: 512-419-5466

Respondents are asked to complete as much information as possible. Some worksheets request data in varying levels of detail, with guidance on the minimum level of information needed. Some worksheets request data for more than one year or more than one production basin, if available. Gaps in the data are OK if the information is not available.

Additional instructions and guidance are provided on each worksheet.

Schedule:

Data indicated in blue font and shading is requested by August 15

Data indicated in green font is requested by September 16, if this level of information available. This more detailed information will help develop more rigorous emissions estimates for these sources.

FIGURE A-2. GAS WELL SURVEY DATA

Table 1. Producing Gas Wells - Activity Data

Please provide the following information for gas producing wells

		Conventional Wells	Unconventional Wells: Shale	Unconventional Wells: Coal-bed Methane	Unconventional Wells: Tight	Year	Geographic Area Represented	Comments
A	Total # of Operating Gas wells							Total of rows A(1) and A(2)
A(1)	# Wells w/out hydraulic fracturing (anytime in their history)							
A(2)	# Wells with hydraulic fracturing (any time in their history)							If counts are not available by vertical and horizontal, please complete this row
A(2)(a)	# Vertical wells with hydraulic fracturing (anytime in their history)							Please provide this level of detail, if available for wells with hydraulic fracturing
A(2)(b)	# Horizontal wells with hydraulic fracturing (anytime in their history)							
B	# Gas well Completions							Total of rows B(1), B(2) and B(3)
B(1)	# Completions for Vertical wells with hydraulic fracturing							Please provide this level of detail, if available
B(2)	# Completions for Horizontal wells with hydraulic fracturing							
B(3)	# Completions for wells without hydraulic fracturing							
C	# Gas well Workovers with hydraulic fracturing (refracs)							Total of rows C(1) and C(2)
C(1)	# Workovers for Vertical wells with hydraulic fracturing							Please provide this level of detail, if available
C(2)	# Workovers for Horizontal wells with hydraulic fracturing							
C(3)	# Workovers for wells without hydraulic fracturing							

Guidance:

2010 data is preferred, with U.S. geographic coverage as broad as possible.

Please duplicate the table to provide data for additional calendar years (if available) or additional geographic areas (if needed).

Note that some of this information overlaps with the data requested under the "Re-frac" worksheet.

Please provide information that you have available.

Blue rows are the minimum level of detail needed

Green rows provide more detailed information and have a longer response time

Geographic area:

Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins)

FIGURE A-3. GAS WELL WORKOVER SURVEY DATA

Table 2. Gas Well Workover Activity Data: Frequency of Re-fractures

	Year	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001
A	*Geographic area*										
B	*Number of Unconventional Operating Gas Wells*										
C	*Number of Fracture Stimulation Wells Completed each year (New Completions)*										
D	*Number of Fracture Stimulation Jobs conducted each year on Previously Fracture Stimulated Wells (i.e., # of Workovers or re-fracs)*										

Guidance

Please provide information that you have available.
Please provide data that are available for any or all of the years listed. Gaps in the data are OK.
Copy the table to provide data for additional geographic areas

A Geographic Area: Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins)

B Provide the number of Unconventional Operating Wells. This refers to wells located on shale, coal-bed Methane, and Tight Formations reservoirs. Unconventional reservoirs are reservoirs that require fracture stimulation to economically produce.

C Provide the number of new completions conducted in the year. This may be the same value provided in the "Well data" worksheet, Item B.

D Provide the number of re-fractures (workovers). A re-frac or workover is defined as a re-completion to a different zone in an existing well or re-stimulation of the same zone in an existing well. This may be the same value provided in the "Well data" worksheet, Item C. Hydraulic Fracture jobs conducted more than 30 days from the end of one stimulation job to the beginning of another stimulation job in the same well-bore is a new re-frac.

Notes

The EPA uses an assumption that 10% of wells are refractured each year to determine the number of re-frac's per year and then multiplies this by 9.175 MMSCF methane per re-frac to arrive at their inventory for this particular category.

For the year reported in Table 1, this table requests redundant information. The purpose of this table is to collect refracture information over a ten-year time period to provide a better estimate to EPA's assumption that 10% of wells are refractured each year.

FIGURE A-4. GAS WELL LIQUIDS UNLOADING SURVEY DATA

Table 3. Gas Well Venting for Liquids Unloading (Well Clean-ups)

A Please indicate if the information provided in Table 3 follows the Subpart W methodologies (yes or no)

		Conventional	Unconventional	Total	Comments
B	Geographic Area				
C	Time Period - Months				
D	Number of Operated Gas Wells Represented by the information provided				Unconventional wells are: Shale, coal-bed methane, and tight formation (sand, carbonate, etc.) that must be fracture stimulated to produce economic quantities of gas
E	Number of Gas Wells with Plunger Lift Installed				
F	Number of Gas Wells with Other Artificial Lift (Beam Pump; ESP; etc.)				
G	Number of Gas Wells Vented to the atmosphere for Liquids Unloading				EPA assumes that 41.3% of conventional gas wells (437,800) are vented for liquids unloading
H	Total number of Gas Well Vents for Time Period				EPA assumes that each venting well vents 38.7 times per year
I	Average Venting Time per Vent				EPA assumes that each venting event is 3 hours duration
J	*Number of Wells with Plunger Lifts that vent to the atmosphere*				This is a sub-category of data item #5. Please indicate here the number of wells that vent to the atmosphere
K	*Total Count of Gas Well Vents for Time Period - w/plunger*				
L	*Total Count of Gas Well Vents for Time Period - w-o/plunger*				
M	*Average Venting Time - w/plunger*				Hours per Vent - fractional hours if appropriate
N	*Average Venting Time - w-o/plunger*				Hours per Vent - fractional hours if appropriate
O	*Average Daily Production of Venting Gas Wells*				mcf/day
P	*Average Depth of Venting Wells*				feet
Q	*Average Casing Diameter of Venting Gas Wells*				inches
R	*Average Tubing Diameter of Venting Gas Wells w/plunger Lift*				inches
S	*Average Surface Pressure - Venting Gas Wells*				psig

Guidance:

This table represents data from a sampling of wells (as opposed to data for all of your wells).

If information is not available by conventional or unconventional wells, just provide data in the "total" column.

A If you do not have data based on Subpart W, please indicate this in data item A by typing yes or no in the shaded box

Copy the table to provide data for additional geographic areas

Please provide information that you have available.

Blue rows are the minimum level of detail needed

Green rows provide more detailed information

B Geographic Area: Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins).

C Time period: Indicate the number of months represented by the information provided. Ideally this is based on some portion of 2011 data collected for Subpart W reporting.

J This data line is a sub-category if data item E. From the difference between these two items, we are trying to determine the fraction of plunger equipped wells that do not vent.

K,L Please enter the number of liquids unloading events where gas is released to the atmosphere.

Notes:

Many companies have likely been tracking well venting for liquids unloading for several months due to Subpart W. API is soliciting information from members to correct/confirm EPA's assumptions regarding well un-loading. If you do not have the wells split out into Conventional and Unconventional categories then simply report the total counts and information in the Conventional categories.

FIGURE A-5. OTHER SURVEY DATA

Table 4. Other Activity Data

A

Centrifugal Compressors			
	Production/ gathering	Processing	
Year			2010 data is preferred, but available information from any recent year is OK
Number of Centrifugal Compressors			Include both engine/turbine driven and electric driven
Number with Dry Seals			
Number with Wet Seals			

B

Pneumatic Devices (Controllers)				
	Well Sites	Gathering/ Compressor Sites	Gas Processing Plants	
Year				2010 data is preferred, but available information from any recent year is OK
Number of Sites/Plants Covered				The total number of wells sites, gathering compressor sites, of gas processing plants represented by the inventory of devices below
Number of Low Bleed				EPA defines low bleed as <6 scfh
Number of High Bleed				EPA defines high bleed as >6 scfh
Number of Intermittent				

Guidance

For pneumatic devices: Do not include counts of devices operated on compressed air. Designate pneumatic devices between "high bleed", "low bleed", or "intermittent" following the approach your company is using for Subpart W reporting.

Appendix B. ANGA/API Well Survey Information

Responses from the API/ANGA survey covered more than 60,000 wells and provided data on:

- # of gas wells without hydraulic fracturing (anytime in their history)
- # of gas wells with hydraulic fracturing (any time in their history);
    - # of vertical gas wells with hydraulic fracturing (anytime in their history);
    - # of horizontal gas wells with hydraulic fracturing (anytime in their history);
- # of completions for vertical gas wells with hydraulic fracturing;
- # of completions for horizontal gas wells with hydraulic fracturing;
- # of completions for gas wells without hydraulic fracturing;
- # of workovers for vertical wells with hydraulic fracturing;
- # of workovers for horizontal wells with hydraulic fracturing; and
- # of workovers for wells without hydraulic fracturing.

Table B-1 summarizes the well data collected by the ANGA/API survey and presents its distribution by formation type and region. The regional distribution follows the National Energy Modeling System (NEMS) regions defined by the EIA. The data are compared to EPA's national well counts classified by type as provided in the August 2011 database file (EPA, 2011d).

Table B-1. API/ANGA Survey – Summary of Gas Well Counts by Type and NEMS Region*

NEMS Region	Conventional Wells	Shale	Coal-bed Methane	Tight	Unspecified
Northeast	12,144	3,541	9	3,874	2,563
Gulf Coast	2,870	1,990	-	7,968	1,521
Mid-Continent	9,081	2,333	-	3,747	5,579
Southwest	646	1,208	-	726	2,326
Rocky Mountain	3,707	366	5,458	18,053	11
West Coast	-	-	-	-	-
Unspecified					1,307
Survey TOTAL	28,448	9,438	5,467	34,368	13,307
% of EPA 2010 Well Counts (from database file)	14.2%	30.1%	11.5%	45.6%	
Overall Survey Total	91,028				
EPA Well Counts (2010, from database file)	200,921	31,381	47,371	75,409	
	56.6%	8.8%	13.3%	21.2%	
	355,082				
EPA National Inventory (2010)	484,795				
EIA National Well Count (2010)	487,627				

* ANGA/API survey data represents well counts current for calendar year 2010 or the first half of 2011.

As shown in Table B-1, data from the API/ANGA survey represent approximately 26% of the national gas wells reported by EPA's database (or 18.7% of the EIA well count data). This includes almost 46% of all tight gas wells and 30% of shale gas wells. This may indicate that the ANGA/API information has an uneven representation of unconventional gas wells, and in particular shale and tight gas wells, but it also appears that EPA's data may mis-categorize these types of wells. For example, the EPA/HPDI data set contains few wells from Pennsylvania and West Virginia while the API/ANGA survey includes 9,422 wells from that area (AAPG 160A).

Table B-2 summarizes additional details on the natural gas wells information collected through the second data collection effort by the ANGA/API survey which covered 60,710 wells.

TABLE B-2. ANGA/API SURVEY – ADDITIONAL DETAILS ON GAS WELL COUNTS*

	# Wells w/out hydraulic fracturing (anytime in their history)	# Wells with hydraulic fracturing (any time in their history)		
		Total	# Vertical wells	# Horizontal wells
TOTAL Conventional	1,498	16,678	14,844	1,834
TOTAL Coal Bed Methane	42	3,475	3,424	42
TOTAL Shale	1,931	9,084	2,012	7,072
TOTAL Tight	122	27,880	24,048	3,835
TOTAL OVERALL	**3,593**	**57,117**	**44,325**	**12,783**

* API/ANGA survey data represents well counts current for calendar year 2010 or the first half of 2011.

Additional information on natural gas wells with and without hydraulic fracturing was provided for approximately two-thirds (60,710 natural gas wells) of the total well data collected by the ANGA/API survey. For this subset of the well data, 94% of the gas wells have been hydraulically fractured at some point in their operating history, including almost 92% of the conventional wells. EPA's 2010 national inventory reported 50,434 gas wells with hydraulic fracturing. This is very similar to the number of unconventional gas wells that EPA reported in the 2009 national inventory. ***Based on the API/ANGA survey results, it appears that EPA has underestimated the number of gas wells with hydraulic fracturing.***

Of the ANGA/API survey responses for wells that have been hydraulically fractured, most (77.6%) are vertical wells. Vertical wells are predominately conventional gas wells, coal-bed methane and tight gas wells; while the majority of shale gas wells are horizontal. EPA does not currently distinguish between vertical and horizontal gas wells.

A Short Note About EPA and EIA's Well Counts

There is a discrepancy of over 132,000 natural gas wells between the EPA database information (EPA, 2011d) and the EIA national gas well counts (EIA, 2012), and a difference of almost 130,000 gas wells between the two EPA data sources (EPA, 2011d and EPA, 2012). This difference needs to be understood since ultimately both the IHS (EIA) and HPDI (EPA) data originate from the same state-level sources of information.

The EIA provides a gas well count of 487,627 for 2010 based on Form EIA-895A[7], the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals

[7] Form EIA-895, Annual Quantity And Value Of Natural Gas Production Report; http://www.eia.gov/survey/form/eia_895/form.pdf

Management Service) data, and World Oil Magazine (EIA, 2010). However, the EIA does not classify gas wells by conventional and unconventional, or by formation types, precluding more detailed comparison against the EIA data. For some parameters the classifications were based on qualitative descriptions of the formations' physical properties (e.g. permeability) rather than on actual measurements (i.e. permeability data in millidarcy readings).[8]

EPA provides a similar well count in the 2010 national inventory: 434,361 non-associated gas wells + 50,434 gas wells with hydraulic fracturing, resulting in a total of 484,795 gas wells (EPA, 2012). Further classification of gas wells or description on what constitutes a "non-associated" gas well versus a "gas well with hydraulic fracturing" is not provided in EPA's national inventory.

Small differences in the HPDI and IHS original data may arise from definitional differences as HPDI and IHS compile the raw data. In addition, each state may have a different interpretation of well definitions of gas versus oil wells that introduces differences among states for the wells reported. EPA had indicated in discussions with the API/ANGA group that their database well count information may not include all of the wells in the Marcellus basin. EIA indicates 44,500 gas wells in Pennsylvania in 2010. However, even in accounting for these wells, there is still a large difference (almost 88,000 wells) between EPA's total gas well number from their database source and EIA's well data.

Nevertheless, these discrepancies among the well counts need to be understood since these data all originate from the same state-level sources of information. Differences could arise, for example, from different interpretations of well definitions.

Since the EIA data is the *de facto* benchmark in the energy industry, the difference between the EIA and EPA well count data needs to be understood before any meaningful conclusions can be made from the EPA data.

Since EPA's well count from HPDI was much lower than the EIA, this report does not attempt to come up with a national gas well count but chose to use the 355,082 number from the EPA HPDI database because it was the only available database which parsed the wells into conventional and unconventional categories (EPA, 2011d).

[8] Information provided by Don Robinson of ICF (EPA's contractor).

Appendix C. Emission Estimates for Gas Well Liquids Unloading

Tables C-1 through C-4 summarize the liquids unloading emissions data collected through the API/ANGA survey and the resulting emission estimates. The emission factors reported in Table 4 are based on a regional weighted average of the conventional and unconventional gas wells, with and without plunger lifts. This provided a consistent comparison against the EPA emission factors which are reported only on a regional basis and do not differentiate between conventional and unconventional wells or wells with and without plunger lifts.

TABLE C-1. LIQUIDS UNLOADING FOR CONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS

NEMS Region	Northeast		Gulf Coast		Mid-Continent		Southwest
# venting gas wells	190	916	12	6	1	38	220
# gas well vents	4,335	39,668	144	60	1	2,444	880
Average casing diameter, inches	5	4.5	5.5	3.65	4.83	4	5.5
Average well depth, feet	3,375	3,448	10,000	19,334	7,033	4,269	8,000
Average surface pressure, psig (for venting wells)	85	50	Applied average 122	224	25.5	60.8	100
Average venting time, hours	1	2	1	2.5	.25	4.95	1
Average gas flow rate, Mscfd	2,861	7,388.5	300	664	58.43	84	100
Total emissions, scf gas/yr	11,503,329	51,547,287	1,961,463	1,322,380	1,548	3,769,194	7,879,520
Emissions per well, scfy gas/well	60,544	56,274	163,455	220,397	1,548	99,189	35,816

TABLE C-2. LIQUIDS UNLOADING FOR CONVENTIONAL GAS WELLS WITH PLUNGER LIFTS

NEMS Region	Northeast		Mid-Continent		
# venting gas wells	33	109	164	2	10
# gas well vents	1,272	4,217	489,912	23	7,300
Average tubing diameter, inches	2	2.375	1.995	2	2.375
Average well depth, feet	3,375	3,448	4,269	7,033	9,500
Average surface pressure, psig (for venting wells)	85	50	60.8	25.5	500
Average venting time, hours	1	0.3	0.067	0.75	0.08
Average gas flow rate, Mscfd	2,861	7,388.5	84	58.43	30
Total emissions, scf gas/yr	599,664	1,517,294	187,255,825	6,713	72,367,809
Emissions per well, scfy gas/well	18,172	13,920	1,141,804	3,357	7,236,781

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS

NEMS Region	Northeast	Gulf Coast					
# venting gas wells	337	6	14	8	27	11	15
# gas well vents	27,720	6	14	104	207	572	15
Average casing diameter, inches	4.5	5.5	5.5	5.5	4.5	5.5	10.75
Average well depth, feet	4,845	6,000	8,500	11,000	9,000	13,752	16,000
Average surface pressure, psig (for venting wells)	121.6	400	3,200	200	50	450	1,671
Average venting time, hours	1.3638	3	4	1	5.3	2	2
Average gas flow rate, Mscfd	26	200	13,000	25	130	353	8,500
Total emissions, scf gas/yr	122,362,610	177,839	5,887,104	2,560,844	722,663	39,633,526	17,501,885
Emissions per well, scfy gas/well	363,094	29,640	420,507	320,106	26,765	3,603,048	1,166,792

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS, CONTINUED

NEMS Region	Gulf Coast				Mid-Continent			
# venting gas wells	146	2	10	40	177	3	136	215
# gas well vents	146	12	120	40	400	7.2	391.2	2,580
Average casing diameter, inches	4.5	5.5	5.5	8.625	5.5	4.92	5.02	5.5
Average well depth, feet	8,500	11,647	11,000	12,500	3,911	10,293	7,888	11,000
Average surface pressure, psig (for venting wells)	15	25	94	661	80	90.04	98.75	200
Average venting time, hours	0.6875	1.5	4	1	2.5	1.58	1.925	0.5
Average gas flow rate, Mscfd	99	83	92	6,500	250	727	875	100
Total emissions, scf gas/yr	139,473	40,837	1,400,265	9,096,858	1,416,389	77,333	2,874,991	63,528,630
Emissions per well, scfy gas/well	955	20,418	140,027	227,421	8,002	25,778	21,140	295,482

Table C-3. Liquids unloading for Unconventional gas wells without plunger lifts, continued

NEMS Region	Southwest			Rocky Mountain		
# venting gas wells	228	6	3	113	2	28
# gas well vents	221	6	1	2,004	4	10,584
Average casing diameter, inches	9.625	5.5	5	4.038	4.7	4.5
Average well depth, feet	8,725	8,000	15,000	11,149	11,056	10,844
Average surface pressure, psig (for venting wells)	208	50	200	250	250	198
Average venting time, hours	1	0.5	6.67	1.616	0.75	3.18
Average gas flow rate, Mscfd	1,500	12	150	127	433	83
Total emissions, scf gas/yr	13,747,516	26,862	63,188	33,701,560	90,364	170,274,852
Emissions per well, scfy gas/well	60,296	4,477	21,063	298,244	45,182	6,081,245

Table C-4. Liquids unloading for Unconventional gas wells with plunger lifts

NEMS Region	Northeast			Gulf Coast				
# venting gas wells	308	103	5	3	2	22	59	5
# gas well vents	63,840	75,190	194	156	2	22	354	5
Average tubing diameter, inches	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Average well depth, feet	4,845	2,500	7,000	13,752	16,000	8,500	11,647	12,500
Average surface pressure, psig (for venting wells)	121.6	200	130	450	1,671	15	25	661
Average venting time, hours	0.2209	0.05	0.1	2	1	0.875	0.3	0.5
Average gas flow rate, Mscfd	26	15	628	353	8,500	99	83	6,500
Total emissions, scf gas/yr	78,496,300	78,461,940	368,444	2,036,862	288,681	7,401	215,123	86,220
Emissions per well, scfy gas/well	254,858	761,766	73,689	678,954	144,341	336	3,646	17,244

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS, CONTINUED

NEMS Region	Mid-Continent				Southwest
# venting gas wells	48	4	64	29	18
# gas well vents	155,742	9.6	170.4	348	25
Average tubing diameter, inches	2.375	3.88	4.11	2.4	1.995
Average well depth, feet	3,911	10,293	7,888	Applied average 9,521	8,725
Average surface pressure, psig (for venting wells)	80	90.04	98.75	74.69	208
Average venting time, hours	0.0833	2.99	2.6	0.5425	0.5
Average gas flow rate, Mscfd	250	727	875	Average applied 1,276.8	1500
Total emissions, scf gas/yr	101,698,021	124,984	906,144	529,679	66,812
Emissions per well, scfy gas/well	2,118,709	31,246	14,158	18,265	3,712

Table C-4. Liquids unloading for Unconventional gas wells with plunger lifts, continued

NEMS Region	Rocky Mountain				
# venting gas wells	247	23	296	19	793
# gas well vents	1,476	51.43	2,080	21,888	9,516
Average tubing diameter, inches	1.997	1.92	2.375	2.375	2.375
Average well depth, feet	11,149	11,164	11,056	10,844	7,400
Average surface pressure, psig (for venting wells)	250	290	250	198	150
Average venting time, hours	0.407	1.12	2.1	0.455	0.67
Average gas flow rate, Mscfd	127	454	433	83	46
Total emissions, scf gas/yr	6,070,440	238,833	12,027,460	98,082,094	22,045,130
Emissions per well, scfy gas/well	24,577	10,384	40,633	5,162,215	27,800

The calculated emissions shown in Tables C-1 through C-4 are based on applying Equation W-8 from 40 CFR 98 Subpart W to gas well liquid unloading without plunger lifts and Equation W-9 to gas well liquid unloading with plunger lifts. The equations and the terms are provided below.

98.233(f)(2) *Calculation Methodology 2.* Calculate the total emissions for well venting for liquids unloading using Equation W–8 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_q \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-8)}$$

Where:

$E_{s,n}$=	Annual natural gas emissions at standard conditions, in cubic feet/year.
W =	Total number of wells with well venting for liquids unloading for each sub-basin.
0.37×10^{-3}=	{3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
CD_p=	Casing internal diameter for each well, p, in inches.
WD_p=	Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.
SP_p=	Shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, p, in pounds per square inch absolute (psia) or casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure of each well, p, in the sub-basin, in pounds per square inch absolute (psia).
V_p=	Number of vents per year per well, p.
SFR_p=	Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.
$HR_{p,q}$=	Hours that each well, p, was left open to the atmosphere during unloading, q.
1.0 =	Hours for average well to blowdown casing volume at shut-in pressure.
$Z_{p,q}$=	If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

98.233(f)(3) *Calculation Methodology 3.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_q \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-9)}$$

Where:

$E_{s,n}$=	Annual natural gas emissions at standard conditions, in cubic feet/year.
W =	Total number of wells with well venting for liquids unloading for each sub-basin.
0.37×10^{-3}=	{3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
TD_p=	Tubing internal diameter for each well, p, in inches.
WD_p=	Tubing depth to plunger bumper for each well, p, in feet.
SP_p=	Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.
V_p=	Number of vents per year for each well, p.
SFR_p=	Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.
$HR_{p,q}$=	Hours that each well, p, was left open to the atmosphere during each unloading, q.
0.5 =	Hours for average well to blowdown tubing volume at flow-line pressure.

$Z_{p,q}$= If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

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LETTER

Coal to gas: the influence of methane leakage

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Abstract Carbon dioxide (CO_2) emissions from fossil fuel combustion may be reduced by using natural gas rather than coal to produce energy. Gas produces approximately half the amount of CO_2 per unit of primary energy compared with coal. Here we consider a scenario where a fraction of coal usage is replaced by natural gas (i.e., methane, CH_4) over a given time period, and where a percentage of the gas production is assumed to leak into the atmosphere. The additional CH_4 from leakage adds to the radiative forcing of the climate system, offsetting the reduction in CO_2 forcing that accompanies the transition from coal to gas. We also consider the effects of: methane leakage from coal mining; changes in radiative forcing due to changes in the emissions of sulfur dioxide and carbonaceous aerosols; and differences in the efficiency of electricity production between coal- and gas-fired power generation. On balance, these factors more than offset the reduction in warming due to reduced CO_2 emissions. When gas replaces coal there is additional warming out to 2,050 with an assumed leakage rate of 0%, and out to 2,140 if the leakage rate is as high as 10%. The overall effects on global-mean temperature over the 21st century, however, are small.

Hayhoe et al. (2002) have comprehensively assessed the coal-to-gas issue. What has changed since then is the possibility of substantial methane production by high volume hydraulic fracturing of shale beds ("fracking") and/or exploitation of methane reservoirs in near-shore ocean sediments. Fracking, in particular, may be associated with an increase in the amount of attendant gas leakage compared with other means of gas production (Howarth et al. 2011). In Hayhoe et al., the direct effects on global-mean temperature of differential gas leakage between coal and gas production are very small (see their Fig. 4). Their estimates of gas

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leakage, however, are less than more recent estimates. Here, we extend and update the analysis of Hayhoe et al. to examine the potential effects of gas leakage on the climate, and on uncertainties arising from uncertainties in leakage percentages.

We begin with a standard "no-climate-policy" baseline emissions scenario, viz. the MiniCAM Reference scenario (MINREF below) from the CCSP2.1a report (Clarke et al. 2007). (Hayhoe et al. used the MiniCAM A1B scenario, Nakićenović and Swart 2000.) We chose MINREF partly because it is a more recent "no-policy" scenario, but also because there is an extended version of MINREF that runs beyond 2,100 out to 2,300 (Wigley et al. 2009). The longer time horizon is important because of the long timescales involved in the carbon cycle where changes to CO_2 emissions made in the 21st century can have effects extending well into the 22nd century. (A second baseline scenario, the MERGE Reference scenario from the CCSP2.1a report, is considered in the Electronic Supplementary Material).

In MINREF, coal combustion provides from 38% (in 2010) to 51% (in 2100) of the emissions of CO_2 from fossil fuels. (The corresponding percentages for gas are 19 to 21%, and for oil are 43 to 28%.) For our coal-to-gas scenario we start with their contributions to energy. It is important here to distinguish between primary energy (i.e., the energy content of the resource) and final energy (the amount of energy delivered to the user at the point of production). For a transition from coal to gas, we assume that there is no change in final energy. As electricity generation from gas is more efficient than coal-fired generation, the increase in primary energy from gas will be less than the decrease in primary energy from coal — the differential depends on the relative efficiencies with which energy is produced.

To calculate the change in fossil CO_2 emissions for any transition scenario we use the following relationship relating CO_2 emissions to primary energy (P)…

$$\mathrm{ECO2} = \mathrm{A\ Pcoal} + \mathrm{B\ Poil} + \mathrm{C\ Pgas} \tag{1}$$

where A, B and C are representative emissions factors (emissions per unit of primary energy) for coal, oil and gas. The emissions factors relative to coal that we use are 0.75 for oil and 0.56 for gas, based on information in EPA's AP-42 Report (EPA 2005). Using the MINREF emissions for CO_2 and the published primary energy data give a best fit emissions factor for coal of 0.027 GtC/exajoule, well within the uncertainty range for this term.

To determine the change in CO_2 emissions in moving from coal to gas under the constraint of no change in final energy we use the equivalent of Eq. (1) expressed in terms of final energy (F). This requires knowing the efficiencies for energy production from coal, oil and gas (i.e., final energy/primary energy). If F=P×(efficiency), then we have

$$\mathrm{ECO2} = (\mathrm{A/a})\mathrm{Fcoal} + (\mathrm{B/b})\mathrm{Foil} + (\mathrm{C/c})\mathrm{Fgas} \tag{2}$$

where a, b and c are the efficiencies for energy production from coal, oil and gas. For changes in final energy (ΔF) in the coal-to-gas case, ΔFoil is necessarily zero. To keep final energy unchanged, therefore, we must have ΔFgas = −ΔFcoal. Hence, from Eq. (2) …

$$\Delta\mathrm{ECO2} = (\Delta\mathrm{Fcoal})(\mathrm{A/a} - \mathrm{C/c}) \tag{3}$$

or …

$$\Delta\mathrm{ECO2} = \mathrm{A}\ \Delta\mathrm{Pcoal}[1 - (\mathrm{C/A})/(\mathrm{c/a})] \tag{4}$$

As ΔPcoal is negative, the first term here is the reduction in CO_2 emissions from the reduction in coal use, while the second term is the partially compensating increase in CO_2

emissions from the increase in gas use. Our best-fit value for A is 0.027 GtC/exajoule, and C/A=0.56. To apply Eq. (4) we need to determine a reasonable value for the relative gas-to-coal efficiency ratio (c/a), which we assume does not change appreciably over time. For electricity generation, the primary sector for coal-to-gas substitution, Hayhoe et al. (2002, Table 2) give representative efficiencies of 32% for coal and 60% for gas. Using these values, Eq. (4) becomes …

$$\Delta \mathrm{ECO2} = 0.027\ \Delta \mathrm{Pcoal}[1 - 0.299] \tag{5}$$

for ΔECO2 in GtC and ΔP in exajoules. Thus, for a unit reduction in coal emissions, there is an increase in emissions from gas combustion of about 0.3 units.

To complete our calculations, we need to estimate the changes in methane, sulfur dioxide and black carbon emissions that would follow the coal-to-gas conversion. Consider methane first. Methane is emitted to the atmosphere as a by-product of coal mining and gas production. Although these fugitive emissions are relatively small, they are important because methane is a far more powerful forcing agent per unit mass than CO_2.

For coal mining we use information from Spath et al. (1999; Figs. C1 and C4). A typical US coal-fired power plant emits 1,100 gCO2/kWh, with an attendant release of methane of 2.18 gCH4/kWh, almost entirely from mining. Thus, for each GtC of CO_2 emitted from a coal-fired power plant, 7.27 TgCH4 are emitted from mining. Spath et al. give other information that can used to check the above result. They give values of 1.91 gCH4 released per ton of coal mined from surface mines, and 4.23 gCH4 per ton from deep mines. As 65% of coal comes from deep mines, the weighted average release is 3.42 gCH4/ton. Since 1 ton of coal, when burned, typically produces 1.83 kgCO2, the amount of fugitive methane per GtC of CO_2 emissions from coal-fired power plants is 6.85 TgCH4/GtC, consistent with the previous result. For our calculations we use the average of these two results, 7.06 TgCH4/GtC; i.e., if CO_2 emissions from coal-fired power generation are reduced by 1 GtC, we assume a concomitant decrease in CH_4 emissions of 7.06 TgCH4. We assume that this value for the USA is applicable for other countries.

For leakage associated with gas extraction and transport we note that every kg of gas burned produces 12/16 kgC of CO_2. If the leakage rate is "p" percent, then, for any given increase in CO_2 emissions from gas combustion, the amount of fugitive methane released is (p/100) (16/12) 1000=13.33 (p) TgCH4/GtC. For a leakage rate of 2.5%, for example (roughly the present leakage rate for conventional gas extraction), this is 33.3 TgCH4/GtC. Because the CO_2 emissions change from gas combustion is much less than that for coal (about 30%; see Eq. (5)), for the 2.5% leakage case this would make the coal mining and gas leakage effects on CH_4 quite similar (but of opposite sign), in accord with Hayhoe et al. (2002, Table 1).

SO_2 emissions are important because coal combustion produces substantial SO_2, whereas SO_2 emissions from gas combustion are negligible. Reducing energy production from coal has compensating effects — reduced CO_2 emissions leads to reduced warming in the long term, but this is offset by the effects of reduced SO_2 emissions which lead to lower aerosol loadings in the atmosphere and an attendant warming (Wigley 1991). For CO_2 and SO_2, emissions factors for coal (from Hayhoe et al. 2002, Table 1) are 25 kgC/GJ and 0.24 kgS/GJ. For each GtC of CO_2 produced from coal combustion, therefore, there will be 19.2 TgS of SO_2 emitted. We can check this using emissions factors from Spath et al. (1999, Figs. C1 and C2). For a typical coal-fired power plant these are 7.3 gSO2/kWh and 1,100 gCO2/kWh. Hence, for each GtC of CO_2 produced from coal combustion, SO_2 emissions will be 12.17 TgS. Effective global emissions factors can also be obtained from published emissions scenarios. For example, for changes over 2000 to 2010 in the MINREF scenario, the emissions factor for coal combustion is approximately 11.6 TgS/GtC.

From these different estimates it is clear that there is considerable uncertainty in the SO_2 emissions factor, echoing in part the widely varying sulfur contents in coal. Furthermore, for future emissions from coal combustion the SO_2 emissions factor is likely to decrease markedly due to the imposition of SO_2 pollution controls (as explained, for example, in Nakićenović and Swart 2000). It is difficult to quantify this effect, a difficulty highlighted, for example, by the fact that, in the second half of the 21st century, many published scenarios show increasing CO_2 emissions, but decreasing SO_2 emissions — with large differences between scenarios in the relative changes.

For the coal-to-gas transition, it is not at all clear how to account for the effects that SO_2 pollution controls, that will likely go on in parallel with any transition from coal to gas, will have on the SO_2 emissions factor. However, future coal-fired plants will certainly employ such controls, so emissions factors for SO_2 will decrease over time. To account for this we assume a value of 12 TgS/GtC for the present (2010) declining linearly to 2 TgS/GtC by 2,060 and remaining at this level thereafter. This limit and the attainment date are consistent with the fact that many of the SRES scenarios tend to stabilize SO_2 emissions at a finite, non-zero value at around this time.

For black carbon (BC) aerosol emissions we use the relationship between BC and SO_2 emissions noted by Hayhoe et al. (2002, p. 125) and make BC forcing proportional to SO_2 emissions. Using best-estimate forcings from the IPCC Fourth Assessment Report, this means that the increase in sulfate aerosol forcing changes due to SO_2 emissions reductions are reduced by approximately 30% by the attendant changes in BC emissions. This is a larger BC effect than in Hayhoe et al. However, compared with the large overall uncertainty in aerosol forcing, the difference between what we obtain here and the results of Hayhoe et al. are relatively small.

For our coal-to-gas emissions scenario we assume that primary energy from coal is reduced linearly (in percentage terms) by 50% over 2010 to 2050 (1.25%/yr), and that the reduction in final energy is made up by extra energy from gas combustion. (A second, more extreme scenario is considered in the Electronic Supplementary Material). In this way, there are no differences in final energy between the MINREF baseline scenario and the coal-to-gas perturbation scenario. Hayhoe et al. consider scenarios where coal production reduces by 0.4, 1.0 and 2.0%/yr over 2000 to 2025. After 2050 we assume no further percentage reduction in coal-based energy (i.e., the reduction in emissions from coal relative to the baseline scenario remains at 50%). This is an idealized scenario, but it is sufficiently realistic to be able to assess the relative importance of different gas leakage rates. We consider leakage rates of zero to 10%,

Baseline and perturbed (coal to gas) primary energy scenarios for coal and gas are shown in Fig. 1, together with the corresponding fossil-fuel CO_2 emissions. The changes in primary energy breakdown are large: e.g., in 2100, primary energy from coal is 37% more than from gas in the baseline case, but 50% less than gas in the perturbed case. The corresponding reduction in emissions is less striking. In the perturbed case, 2100 emissions are reduced only by 19%. (Cases where there are larger emissions reductions are considered in the Electronic Supplementary Material).

To determine the consequences of the coal-to-gas scenario we use the MAGICC coupled gas-cycle/upwelling-diffusion climate model (Wigley et al. 2009; Meinshausen et al. 2011). These are full calculations from emissions through concentrations and radiative forcing to global-mean temperature consequences. We do not make use of Global Warming Potentials (as in Howarth et al. 2011, for example), which are a poor substitute for a full calculation

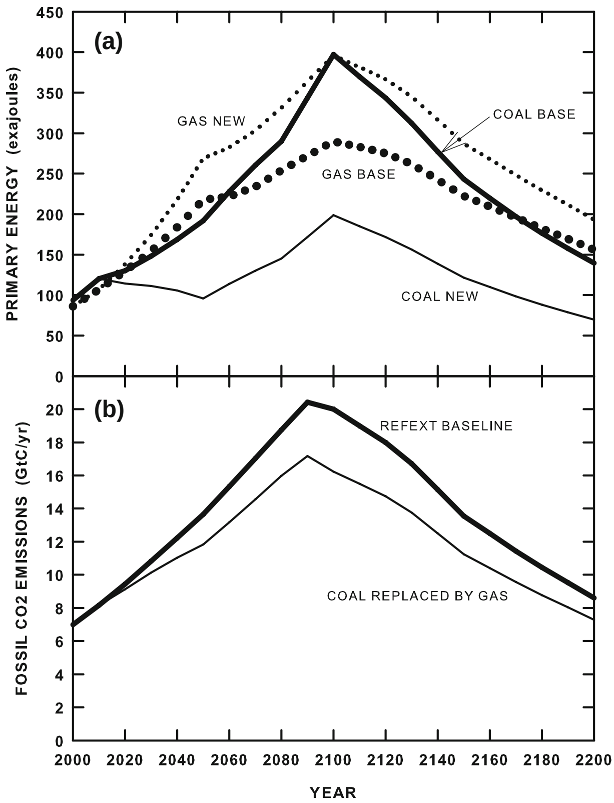

Fig. 1 **a** Primary energy scenarios. Baseline data to 2100 are from the CCSP2.1a MiniCAM Reference scenario. After 2100, baseline primary energy data have been constructed to be consistent with emissions data in the extended MiniCAM Reference scenario (Wigley et al. 2009 — REFEXT). Full lines are for coal, dotted lines are for gas. "NEW" data correspond to the coal-to-gas scenario. Under the final energy constraint that ΔFgas = −ΔFcoal, ΔPgas = −(a/c) ΔPcoal = −0.533 ΔPcoal. **b** Corresponding fossil CO_2 emissions data

(see, e,g., Smith and Wigley 2000a, b). MAGICC considers all important radiative forcing factors, and has a carbon cycle model that includes climate feedbacks on the carbon cycle. Methane lifetime is affected by atmospheric loadings on methane, carbon monoxide, nitrogen oxides (NOx) and volatile organic compounds. The effects of methane on tropospheric ozone and stratospheric water vapor are considered directly. For component forcing values we use central estimates as given in the IPCC Fourth Assessment Report (IPCC 2007, p.4). We also assume a central value for the climate sensitivity of 3°C equilibrium warming for a CO_2 doubling. (A second case using a higher sensitivity is considered in the Electronic Supplementary Material).

Figure 2 shows the relative and total effects of the coal-to-gas transition for a leakage rate of 5%. This is within the estimated leakage rate range (1.7–6.0%; Howarth et al. 2011) for conventional methane production (the effects of well site leakage, liquid uploading and gas processing, and transport, storage and processing). For methane from shale, Howarth et al. estimate an additional leakage of 1.9% (their Table 2) with a range of 0.6–3.2% (their Table 1). The zero to 10.0% leakage rate range considered here spans these estimates — although we note that the high estimates of Howarth et al. have been criticized (Ridley 2011, p. 30).

The top panel of Fig. 2 shows that the effects of CH_4 leakage and reduced aerosol loadings that go with the transition from coal to gas can appreciably offset the effect of reduced CO_2 concentrations, potentially (see Fig. 3) until well into the 22nd century. For the leakage rate ranges considered here, however, the overall effects of the coal to gas transition on global-mean temperature are very small throughout the 21st century, both in absolute and relative terms (see Fig. 2a). This is primarily due to the relatively small reduction in CO_2 emissions that is effected by the transition away from coal (see Fig. 1b). Cases where the CO_2 emissions reductions are larger (due to a more extreme substitution scenario, or a different baseline) are considered in the Electronic Supplementary Material. The relative contributions to temperature change are similar, but the magnitudes of temperature change scale roughly with the overall reduction in CO_2 emissions.

Figure 3 shows the sensitivity of the temperature differential to the assumed leakage rate. The CO_2 and aerosol terms are independent of the assumed leakage rate, so we only show the methane and total-effect results. These results are qualitatively similar to those of Hayhoe et al. who considered only a single leakage rate case (corresponding approximately to our 2.5% leakage case). For leakage rates of more than 2%, the methane leakage contribution is positive (i.e., replacing coal by gas produces higher methane concentrations) — see the "CH4 COMPONENT" curves in Fig. 3. Depending on leakage rate, replacing coal by gas leads, not to cooling, but to additional warming out to between 2,050 and 2,140. Initially, this is due mainly to the influence of SO_2 emissions changes, with the effects of CH_4 leakage becoming more important over time. Even with zero leakage from gas production, however, the cooling that eventually arises from the coal-to-gas transition is only a few tenths of a degC (greater for greater climate sensitivity — see Electronic Supplementary Material). Using climate amelioration as an argument for the

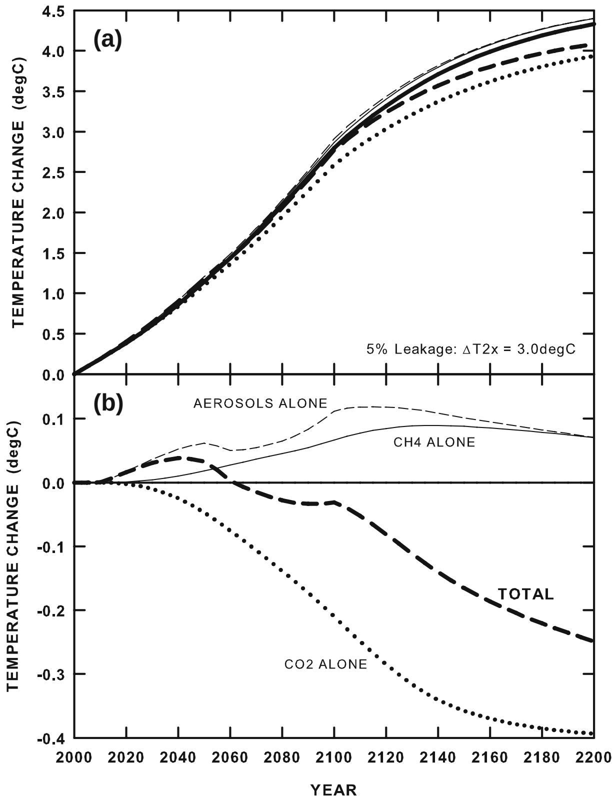

Fig. 2 **a** Baseline global-mean warming (*solid bold line*) from the extended CCSP2.1a Mini-CAM reference scenario together with the individual and total contributions due to reduced CO_2 concentrations, reduced aerosol loadings and increased methane emissions for the case of 5% methane leakage. The *bold dashed line* gives the result for all three components, the *dotted line* shows the effect of CO_2 alone. The *top two thin lines* show the CH_4 and aerosol components. **b** Detail showing differences from the baseline

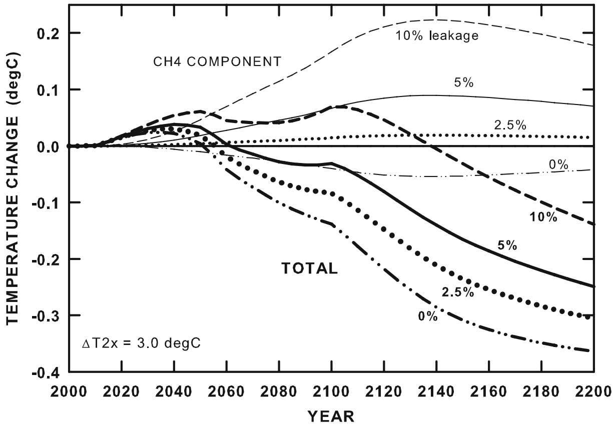

Fig. 3 The effects of different methane leakage rates on global-mean temperature. The *top four curves* (CH4 COMPONENT) show the effects of methane concentration changes, while the *bottom four curves* (TOTAL) show the total effects of methane changes, aerosol changes and CO_2 concentration changes. The latter two effects are independent of the leakage rate, and are shown in Fig. 2. Results here are for a climate sensitivity of 3.0°C

transition is, at best, a very weak argument, as noted by Hayhoe et al. (2002), Howarth et al. (2011) and others.

In summary, our results show that the substitution of gas for coal as an energy source results in increased rather than decreased global warming for many decades — out to the mid 22nd century for the 10% leakage case. This is in accord with Hayhoe et al. (2002) and with the less well established claims of Howarth et al. (2011) who base their analysis on Global Warming Potentials rather than direct modeling of the climate. Our results are critically sensitive to the assumed leakage rate. In our analysis, the warming results from two effects: the reduction in SO_2 emissions that occurs due to reduced coal combustion; and the potentially greater leakage of methane that accompanies new gas production relative to coal. The first effect is in accord with Hayhoe et al. In Hayhoe et al., however, the methane effect is in the opposite direction to our result (albeit very small). This is because our analyses use more recent information on gas leakage from coal mines and gas production, with greater leakage from the latter. The effect of methane leakage from gas production in our analyses is, nevertheless, small and less than implied by Howarth et al.

Our coal-to-gas scenario assumes a linear decrease in coal use from zero in 2010 to 50% reduction in 2050, continuing at 50% after that. Hayhoe et al. consider linear decreases from zero in 2000 to 10, 25 and 50% reductions in 2025. If these authors assumed constant reduction percentages after 2025, then their high scenario is very similar to our scenario.

In our analyses, the temperature differences between the baseline and coal-to-gas scenarios are small (less than 0.1°C) out to at least 2100. The most important result, however, in accord with the above authors, is that, unless leakage rates for new methane can be kept below 2%, substituting gas for coal is not an effective means for reducing the magnitude of future climate change. This is contrary to claims such as that by Ridley (2011) who states (p. 5), with regard to the exploitation of shale gas, that it will "accelerate the decarbonisation of the world economy". The key point here is that it is not decarbonisation *per se* that is the goal, but the attendant reduction of climate change. Indeed, the shorter-term effects are in the opposite direction. Given the small climate differences between the baseline and the coal-to-gas scenarios, decisions regarding further exploitation of gas reserves should be based on resource availability (both gas and water), the economics of extraction, and environmental impacts unrelated to climate change.

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Greenhouse gases, climate change and the transition from coal to low-carbon electricity

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Greenhouse gases, climate change and the transition from coal to low-carbon electricity

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Abstract
A transition from the global system of coal-based electricity generation to low-greenhouse-gas-emission energy technologies is required to mitigate climate change in the long term. The use of current infrastructure to build this new low-emission system necessitates additional emissions of greenhouse gases, and the coal-based infrastructure will continue to emit substantial amounts of greenhouse gases as it is phased out. Furthermore, ocean thermal inertia delays the climate benefits of emissions reductions. By constructing a quantitative model of energy system transitions that includes life-cycle emissions and the central physics of greenhouse warming, we estimate the global warming expected to occur as a result of build-outs of new energy technologies ranging from 100 GW_e to 10 TW_e in size and 1–100 yr in duration. We show that rapid deployment of low-emission energy systems can do little to diminish the climate impacts in the first half of this century. Conservation, wind, solar, nuclear power, and possibly carbon capture and storage appear to be able to achieve substantial climate benefits in the second half of this century; however, natural gas cannot.

Keywords: climate change, bulk electricity supply, central-station greenhouse gas emissions, electricity, climate
S Online supplementary data available from stacks.iop.org/ERL/7/014019/mmedia

1. Introduction

Hoffert *et al* [1] estimated that if economic growth continues as it has in the past, 10–30 TW of carbon-neutral primary power must be deployed by 2050 to meet global energy demand while stabilizing CO_2 concentrations at 450 ppmv, and that even more rapid deployment of new technologies would need to occur in the second half of this century. Pacala and Socolow [2] have suggested that a broad portfolio of existing technologies could put us on a trajectory toward stabilization in the first half of this century. No previous study, however, has predicted the climate effects of energy system transitions.

Fossil fuels, such as coal and natural gas, emit greenhouse gases when burned in conventional power plants. Concern about climate change has motivated the deployment of lower-GHG-emission (LGE) power plants, including wind, solar photovoltaics (PV), nuclear, solar thermal, hydroelectric, carbon capture and storage, natural gas and other energy technologies with low GHG emissions. Electricity generation accounts for approximately 39% of anthropogenic carbon dioxide emissions [3, 4].

Because LGE power plants have lower operating emissions, cumulative emissions over the lifetime of the plants are lower than for conventional fossil-fueled plants of equivalent capacity. LGE power plants typically require greater upfront emissions to build, however. Consequently, rapid deployment of a fleet of LGE power plants could initially increase cumulative emissions and global mean surface temperatures over what would occur if the same net electrical output were generated by conventional coal-fired plants. Our results show that most of the climate benefit of a transition to LGE energy systems will appear only after the transition is complete. This substantial delay has implications for policy aimed at moderating climate impacts of the electricity generation sector.

2. Models of LGE energy system build-outs

To make our assumptions clear and explicit, we used simple mathematical models to investigate the transient effects of energy system transitions on GHG concentrations, radiative forcing and global mean temperature changes. We represent an electric power plant's life in two phases: construction and operation. Our model assumes that each plant produces a constant annual rate of GHG emissions as it is constructed and a different constant emission rate as it operates. Emission rates were taken from the literature (see table S1 in the supplementary online material (SOM) available at stacks.iop.org/ERL/7/014019/mmedia). IPCC-published formulas for the atmospheric lifetime of GHGs [5] are used to model increases in atmospheric GHG concentrations that result from the construction and operation of each power plant (see SOM text SE1 for details). Radiative forcing as a function of time, $\Delta F(t)$, follows directly from GHG concentration using expressions from the IPCC [5].

We estimated the change in surface temperature, ΔT by using a simple energy-balance model. The radiative forcing ΔF supplies additional energy into the system. Radiative losses to space are determined by a climate feedback parameter, λ. We used $\lambda = 1.25$ W m^2 K^{-1} [6–8], which yields an equilibrium warming of 3.18 K resulting from the radiative forcing that follows a doubling of atmospheric CO_2 from 280 to 560 ppmv. The approach to equilibrium warming is delayed by the thermal inertia of the oceans. We represented the oceans as a 4 km thick, diffusive slab with a vertical thermal diffusivity $k_v = 10^{-4}$ m^2 s^{-1} [8]. Other parameter choices are possible, but variations within reason would not change our qualitative results, and this approach is supported by recent tests with three-dimensional models of the global climate response to periodic forcing [9]. Our simple climate model treats direct thermal heating in the same way as radiative heating; heat either mixes downward into the ocean or radiates outward to space. To isolate the effects of a transition to LGE energy systems, we consider GHG emissions from only the power plant transition studied. Initial, steady-state atmospheric GHG concentrations are set to $P_{CO_2} = 400$ ppmv, $P_{CH_4} = 1800$ ppbv, and $P_{N_2O} =$ 320 ppbv, at which $\Delta F = \Delta T = 0$. (Use of other background concentrations for GHGs would not alter our qualitative results (SOM text SE1.3 available at stacks.iop.org/ERL/7/014019/mmedia)).

Although life-cycle estimates of emissions from individual power plants (SOM table S1 available at stacks.iop.org/ERL/7/014019/mmedia) vary, they show a consistent pattern at both the low and high ends of the range, as seen in figures 1(A) and (B). For renewable plants, peak emissions occur during plant construction. For fossil-fueled plants, in contrast, operating emissions dominate; typically $<1\%$ of lifetime plant emissions are attributable to construction. For nuclear plants, both construction and fueling for ongoing operation make substantial contributions to lifetime GHG emissions, although these emissions are far lower than the emissions from coal-fired power plants. The primary GHG emission from hydroelectric plants is methane (CH_4) produced by anaerobic decay of organic matter that is inundated as the reservoir fills [10–12]; the amount emitted varies with local conditions.

To provide a stable supply of electricity, a new power plant must be built as each old power plant nears the end of its useful life. As shown in figures 1(C) and (D), fossil-fueled plants produce a comparatively smooth increase in atmospheric GHG concentrations because emissions during construction are small compared to those from operations. In contrast, the larger contribution during construction of nuclear and renewable power plants produces increased emissions each time a plant of this kind is replaced, yielding a sawtooth trend in atmospheric GHG concentrations for a constant output of electricity.

Construction and operation of a new power plant of any technology modeled here will produce higher atmospheric CO_2 concentrations than would have occurred if no new generating capacity were added. Carbon dioxide poses a special concern because of its long lifetime in the atmosphere. With the exception of dams, carbon dioxide emissions dominate the GHG radiative forcing from power plants. Radiative forcing due to CH_4 and N_2O at any point in time accounts for $<1\%$ of the total GHG forcing from wind, solar and nuclear power plants; $<5\%$ for coal-fired plants; and $<10\%$ for natural gas plants. CH_4 dominates only in the case of hydroelectric power, for which it contributes $\sim 95\%$ of the radiative forcing in the first 20 yr, declining monotonically to $\sim 50\%$ at 70 yr after construction.

We contrasted LGE energy technologies with a high-GHG-emission (HGE) energy technology, namely conventional coal-based electricity production. We define 'HGE warming' to mean the increase in global mean surface temperature that would have been produced by the continued operation of the coal-based HGE energy system. This warming is additional to any temperature increases occurring as a result of past or concurrent emissions from outside the 1 TW_e energy system considered here.

To illustrate the consequences of rapid deployments of new energy systems, we considered emissions from a variety of linear energy system transitions, each of which replaces 1 TW_e of coal-based electricity by bringing new LGE power plants online at a constant rate over a 40 yr period. (1 TW_e is the order of magnitude of the global electrical output currently generated from coal [10].) Existing coal-fired generators were assumed to be new at the onset of the transition, to be replaced with equivalent plants at the end of their lifetime, and to be retired at the rate of new plant additions in order to maintain constant annual output of electricity. Lifetimes

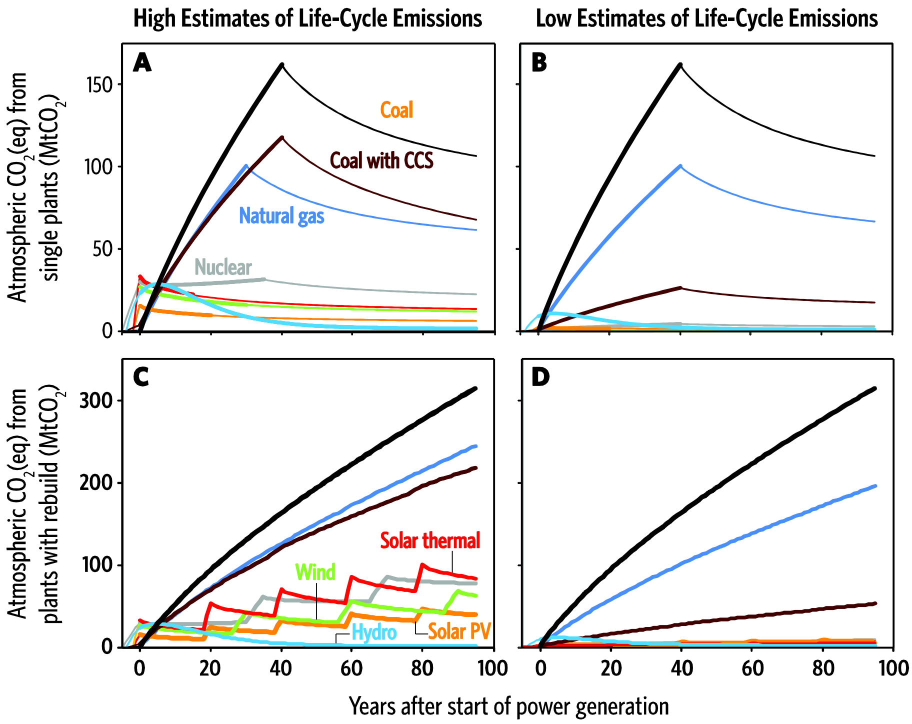

Figure 1. The time evolution of atmospheric CO_2(eq) concentrations resulting from the construction and operation of a 1 GW_e electric power plant varies widely depending on the type of plant. (A), (B) Atmospheric CO_2(eq) concentrations from single power plants of different types based on high (A) and low (B) estimates of life-cycle power plant emissions. Renewable technologies have higher emissions in the construction phase (thin lines prior to year zero); conventional fossil technologies have higher emissions while operating (thick lines); emitted gases persist in the atmosphere even after cessation of operation (thin lines after year zero). The operating life of plants varies by plant type. (C), (D) Atmospheric CO_2(eq) concentrations from the construction of series of power plants built to maintain 1 GW_e output. For high estimates of life-cycle emissions, periodic replacement of aging plants produces pulses of emissions resulting in substantial, step-like change in atmospheric concentrations. However, in all cases except hydroelectric, continued electricity production results in increasing trends of atmospheric CO_2(eq) concentrations.

and thermal efficiencies of the coal plants were taken from the life-cycle analysis (LCA) literature, as were the additional emissions associated with constructing power plants (SOM table S1 available at stacks.iop.org/ERL/7/014019/mmedia). Using GHG emission data from this literature, we calculated time series for emissions, radiative forcing, and temperature for build-outs of eight LGE energy technologies, for a range of rollout durations (SOM text SN3 available at stacks.iop.org/ERL/7/014019/mmedia) including, as a lower bound, the unrealistic case in which all plants are built simultaneously in a single year. Climate consequences of a portfolio of technologies can be approximated by a linear combination of our results for each technology taken individually. For each technology, we examine low and high emission estimates from the LCA literature, and label these ‘Low’ and ‘High’. The time evolution of emissions and temperature increases resulting from an example transition, from coal to natural gas, is illustrated in SOM table S4 (available at stacks.iop.org/ERL/7/014019/mmedia).

We investigated transitions from an HGE energy system to various LGE options for a wide range of transition rates (figure 4). Building on previous life-cycle analyses (SOM table S1 available at stacks.iop.org/ERL/7/014019/mmedia), we estimated the magnitude of most direct and indirect GHG emissions from the construction and operation of the power plants, including GHG emissions associated with long-distance electricity transmission and thermal emissions attributable to power generation and use (SOM text SN2 available at stacks.iop.org/ERL/7/014019/mmedia). During this transition, GHG emissions attributed to the fleet include both those due to construction or operation of the new technology and those due to coal-fired generators that have not yet been replaced. Various energy system transitions could be imagined. Delaying the transition delays long-term climate benefits of LGE energy. Accelerating the transition decreases total fleet emissions from burning coal, but increases the rate of emissions produced by new construction (figure 4(C)). Qualitatively similar results hold for exponential and logistic growth trajectories (SOM text SD1 and figures S10–12 available at stacks.iop.org/ERL/7/014019/mmedia).

3. Delayed benefits from energy system transitions

By the time any new power plant begins generating electricity, it has incurred an ‘emissions debt’ equal to the GHGs released to the atmosphere during its construction. The size of this debt varies from one LGE technology to another, as does the operating time required to reach a break-even point at which emissions avoided by displacing power from an HGE plant equal the emissions debt. All transitions from coal to other energy technologies thus show higher GHG concentrations

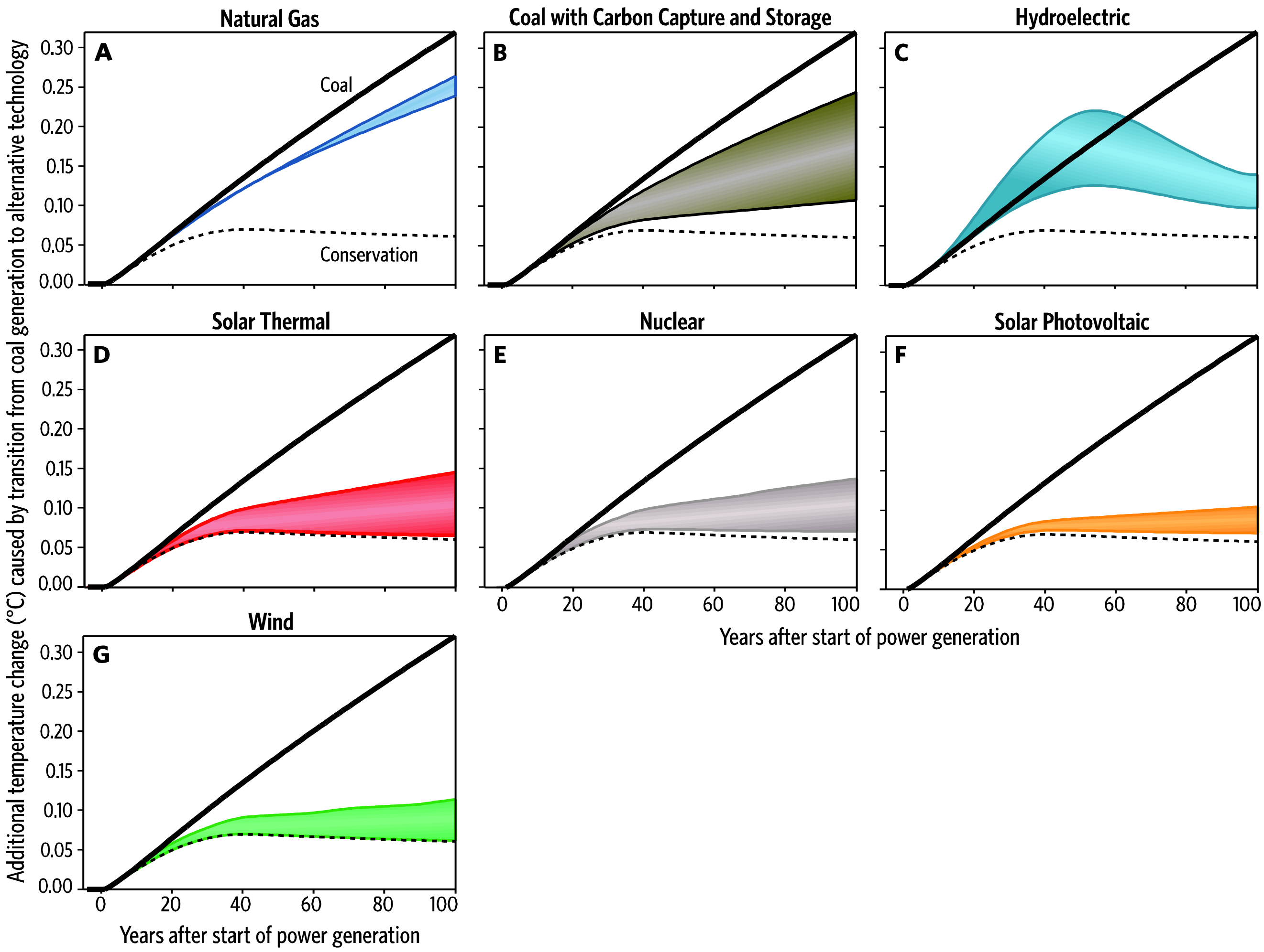

Figure 2. Many decades may pass before a transition from coal-based electricity to alternative generation technologies yields substantial temperature benefits. Panels above show the temperature increases predicted to occur during a 40 yr transition of 1 TW_e of generating capacity. Warming resulting from continued coal use with no alternative technology sets an upper bound (solid black lines), and the temperature increase predicted to occur even if coal were replaced by idealized conservation with zero CO_2 emissions (dashed lines) represents a lower bound. The colored bands represent the range of warming outcomes spanned by high and low life-cycle estimates for the energy technologies illustrated: (A) natural gas, (B) coal with carbon capture and storage, (C) hydroelectric, (D) solar thermal, (E) nuclear, (F) solar photovoltaic and (G) wind.

and temperatures at the outset than would have occurred in the absence of a transition to a new energy system. We calculated, for each technology, the number of years following the start of electricity generation until the transition starts reducing HGE warming, as well as the times at which the transition has reduced HGE warming by 25% or 50%.

Our results (figure 2 and SOM tables S3 and S4 available at stacks.iop.org/ERL/7/014019/mmedia) illustrate the general finding that emerges from our results: energy system transitions cause reductions in HGE warming only once they are well underway, and it takes much longer still for any new system to deliver substantial climate benefits over a conventional coal-based system. It is instructive to examine idealized energy conservation, considered here as a technology that produces electricity with zero GHG emissions. Conservation is thus equivalent to phasing out 1 TW_e of coal power over 40 yr without any replacement technology. Even in this case, GHGs (particularly CO_2) emitted by coal during the phaseout linger in the atmosphere for many years; in addition, ocean thermal inertia causes temperature changes to lag radiative forcing changes. Consequently, conservation takes 20 yr to achieve a 25% reduction in HGE warming and 40 yr to achieve a 50% reduction.

This idealized rollout of conservation that displaces 1 TW_e of conventional coal power sets a lower bound to the temperature reductions attainable by any technology that does not actively withdraw GHGs from the atmosphere. This lower bound is approached most closely by wind, solar thermal, solar PV and nuclear, using the low LCA estimates; these cases yield temperature increases that exceed the idealized conservation case by only a fraction of a degree, and the time to a 50% reduction in HGE warming is delayed by only a few years. Differences among these same technologies appear, however, if high LCA estimates are used (figure 3). When using the complete range of LCA estimates, for example, our model projects that a 40 yr, linear transition from coal to solar PV would cause a 1.4–6.9 yr period with greater warming than

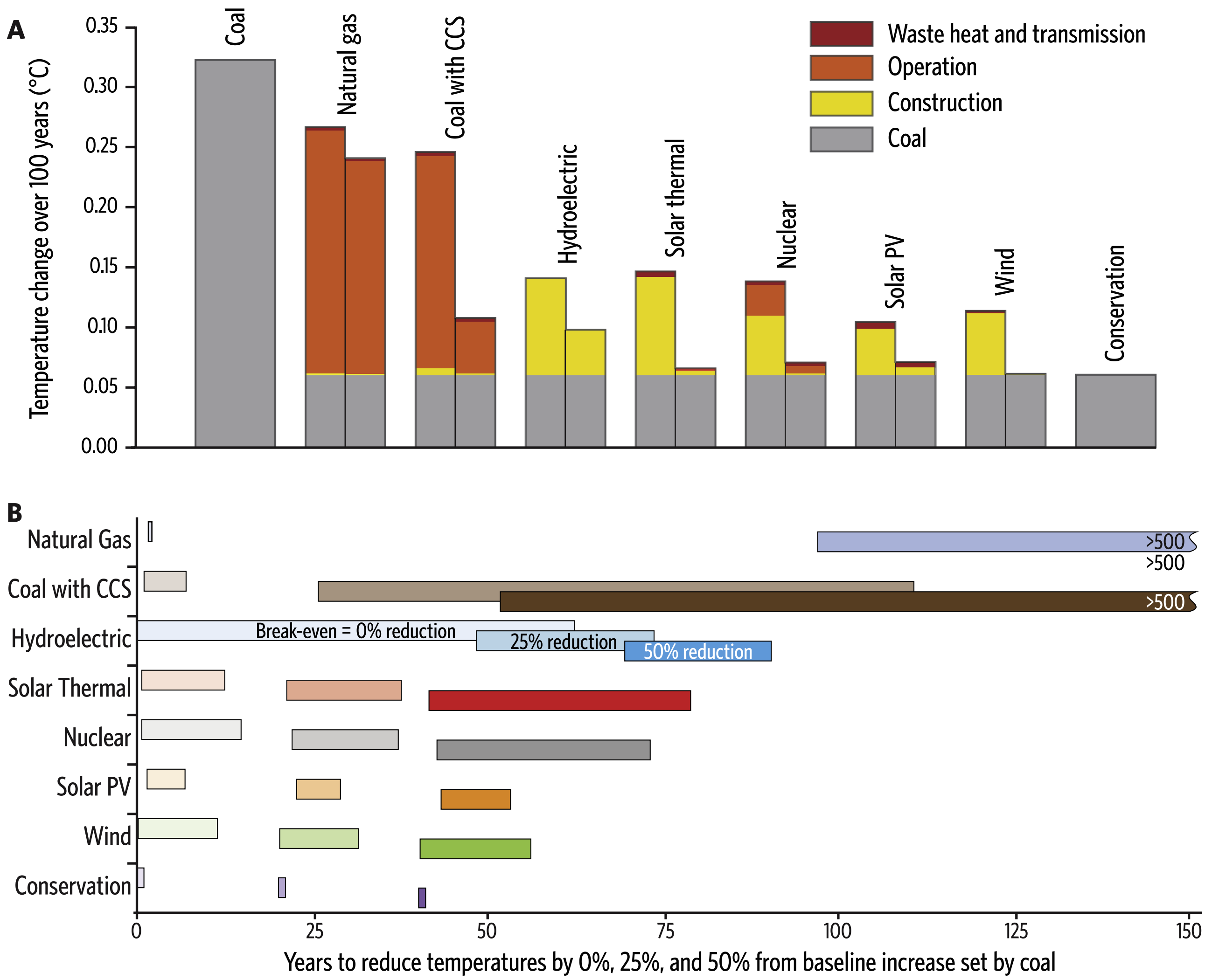

Figure 3. Transitions of 1 TW_e of coal-based electricity generation to lower-emitting energy technologies produces modest reductions in the amount of global warming from GHG emissions; if the transition takes 40 yr to complete, only the lowest-emission technologies can offset more than half of the coal-induced warming in less than a century. (A) Increases in global mean surface temperature attributable to the 1 TW_e energy system 100 yr after the start of a 40 yr transition to the alternative technology. Even if the coal-based system were phased out without being replaced by new power plants of any kind, GHGs released by the existing coal-fired plants during the phaseout would continue to add to global warming (rightmost column). Split columns reflect temperature changes calculated using both high and low emissions estimates from a range of life-cycle analyses, as described in the text and SOM text SN2 (available at stacks.iop.org/ERL/7/014019/mmedia). (B) Time required from the start of power generation by an alternative technology to achieve break-even, warming equal to what would have occurred without the transition from coal (lightest shading); a 25% reduction in warming (medium shading); and a reduction by half (darkest shading) as a result of the transition. The bars span the range between results derived using the lowest and highest LCA estimates of emissions. For numeric values, see SOM table S3 (available at stacks.iop.org/ERL/7/014019/mmedia).

had the transition not been undertaken, and that the transition would take 23–29 yr to produce a 25% reduction in HGE warming and 43–53 yr to avoid half of the HGE warming.

Natural gas plants emit about half the GHGs emitted by coal plants of the same capacity, yet a transition to natural gas would require a century or longer to attain even a 25% reduction in HGE warming (SOM table S3 available at stacks.iop.org/ERL/7/014019/mmedia). Natural gas substitution thus may not be as beneficial in the near or medium term as extrapolation from 'raw' annual GHG emissions might suggest.

Carbon capture and storage (CCS) also slows HGE warming only very gradually. Although CCS systems are estimated to have raw GHG emissions of ∼17%–∼27% that of unmodified coal plants, replacement of a fleet of conventional coal plants by coal-fired CCS plants reduces HGE warming by 25% only after 26–110 yr. This transition delivers a 50% reduction in 52 years under optimistic assumptions and several centuries or more under pessimistic assumptions.

More generally, any electricity-generating technology that reduces GHG emissions versus coal plants by only a factor of two to five appears to require century-long times to accrue substantial temperature reductions. Comparison of 1 TW_e, 40 yr transitions from coal to a wide range of LGE energy technologies reveals little difference in warming produced by the various technologies until the transition is complete (figures 2(A)–(G)). Although it takes many decades

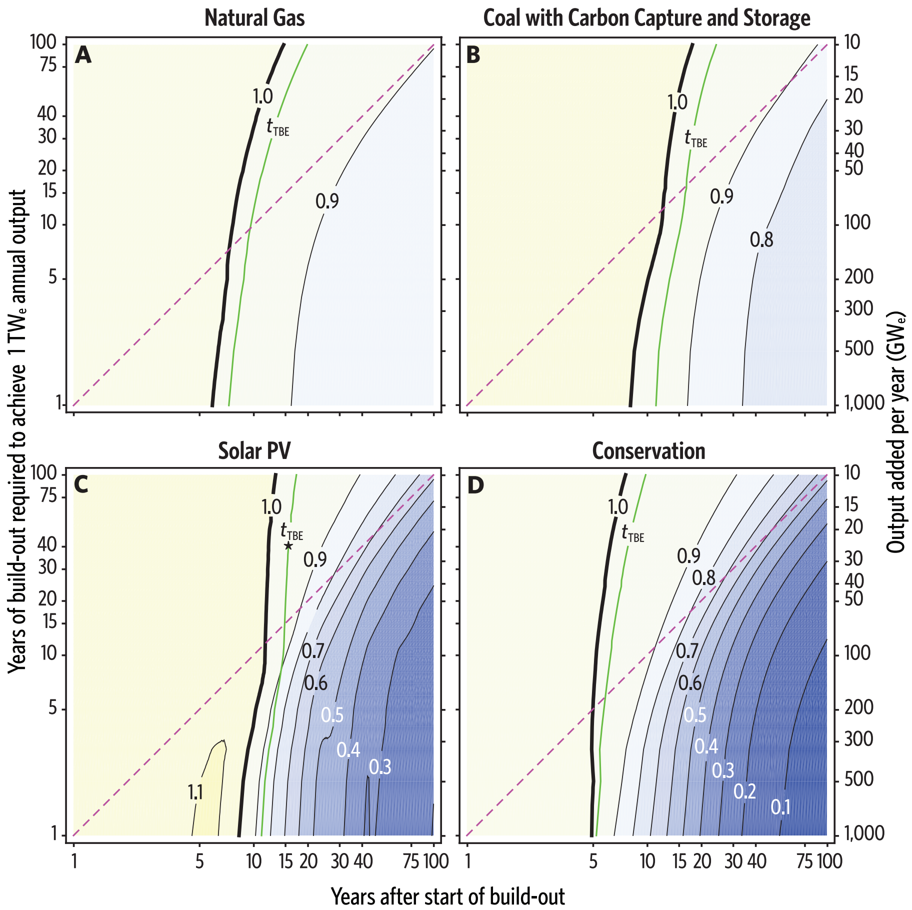

Figure 4. Analysis of a wide range of energy transition rates, scales, and technologies finds that replacement of coal-fired power plants requires many years to deliver climate benefits. For a given alternative energy technology and transition scale, the range of simulation results can be summarized by a contour plot; those above show results for 1 TW_e, linear transitions to (A) natural gas, (B) coal with CCS, (C) solar PV and (D) conservation; high emission estimates from LCA studies were used in each case. For plots of other technologies, transition scales, and build-out trajectories, see SOM figures S10 and S11 (available at stacks.iop.org/ERL/7/014019/mmedia). In these plots, the vertical axis represents the duration of the build-out; results span build-out durations from 1 to 100 yr, which corresponds to annual additions of output ranging from 10 to 1000 GW_e. Contour lines plot the ratio $\Delta T_{new}/\Delta T_{coal}$, where ΔT_{new} is the increase in global mean surface temperature projected to result from the transition to the lower-emission technology. Contour lines thus represent the time to achieve reductions in warming ranging from 10% (a ratio of 0.9) to 90% (a ratio of 0.1). Whereas the progress of the build-out (horizontal axis) is measured from the start of power generation in figure 3, here time is measured from the start of construction, which we assume lasts five years before each new plant begins generating. (For ease of comparison, conservation is treated similarly.) Dashed magenta lines indicate the completion of construction of the last plant in the build-outs. The instantaneous break-even point at which $\Delta T_{new} = \Delta T_{coal}$ is indicated by thick black curves. A better metric of the break-even time, however, is where the time-averaged integral of ΔT_{new} equals that of ΔT_{coal} (t_{TBE}, green curves). A 40 yr deployment of 1 TW_e of solar PV, for example, would not reach t_{TBE} until year 15 of the build-out (asterisked point).

to achieve substantial benefits from a phaseout of coal-based power plants, instantaneously turning coal plants off without replacing the generating capacity would yield a 50% reduction in HGE warming in 11 yr, as shown in figure 4(D), which plots the reduction in temperature increases to be expected in any given year from elimination of 1 TW_e of coal capacity by build-outs ranging in duration from 1 to 100 yr.

We selected coal-fired plants as the basis for comparison because this energy technology emits the most GHGs per unit electricity generated; replacing plants of this kind thus delivers the greatest climate benefits. If the new technology were instead to replace natural gas plants, then even less CO_2 emission would be avoided, and the times to achieve reductions in warming relative to a natural gas baseline would be even longer than projected here.

4. Effects of scale, duration, technological improvement and bootstrapping

Although we focus here on 40 yr, linear transitions of a 1 TW_e energy system, we examined a far broader range of cases; none of these cases altered our central conclusions. Figure 4, for example, illustrates the HGE warming caused by transitions to several LGE energy technologies that range in duration from 1 to 100 yr. We have simulated transitions ranging from 0.1 to 10 TW_e. In addition to the linear transition presented here, we examined exponential and logistic transitions (SOM texts SD1–SD3 and figures S8, S11–S14 available at stacks.iop.org/ERL/7/014019/mmedia). We also analyzed plausible effects of technological improvement by reducing the emission per unit energy generation over time by various exponential rates, an approach that effectively forces each technology under study to approach the zero emission case of conservation asymptotically (SOM text SD3 and figure S14 available at stacks.iop.org/ERL/7/014019/mmedia). The analysis reveals that the long timescale required for energy system transitions to reduce temperatures substantially is not sensitive to technological improvement. High rates of technological improvement could alter, however, the relative rank of energy technologies in their abilities to mitigate future warming.

Finally, we examined 'bootstrapping' transitions. The exponential, linear and logistic models all assume that generated electricity is used to displace coal and thus lower emissions. A very different strategy is to use a low-GHG-emitting technology to bootstrap itself. This strategy is particularly interesting for wind and solar PV because each of them require substantial amounts of electricity in the manufacturing of key components.

A bootstrapping transition uses electricity from the first plant built to manufacture more plants of the same kind, which in turn provide energy to build new plants, and so on exponentially (SOM text SD2 and figure S13 available at stacks.iop.org/ERL/7/014019/mmedia). In this approach, however, no electricity is turned over to the grid—and thus no coal is replaced—until the build-out goal has been installed and brought online, at which point the coal is displaced all at once. The effect of bootstrapping is thus equivalent to distributing the electrons from PV systems and using coal-generated electrons to construct the PV arrays.

Emissions estimates from the LCA studies we use in our principal analysis, in contrast, assume carbon intensities lower than that of coal-based electricity and thus lower emissions than would occur with either bootstrapping or coal as the source of energy for new plant construction. For both wind and solar, bootstrapping produces higher temperatures during the first 70–100 yr than would occur if the plants were constructed using power from the existing grid. For transitions lasting longer than 100 yr, bootstrapping does yield lower GHG emissions for plant construction and, eventually, lower temperatures than grid-connected build-outs. On this extended time scale, however, emissions for grid-connected models are likely to fall substantially as well, due to changes in the mix of electricity generation.

Figure 3(A) shows that, for fossil fuel plants, emissions from plant operation are the predominant source of life-cycle emissions, and they are responsible for the majority of the global temperature increase produced. Conservation yields the largest temperature reductions. In transitions to wind, solar, and nuclear technologies, temperature increases caused by emissions during plant construction exceed those due to plant operation; the resulting temperature increases are dwarfed, however, by those caused by emissions from coal plants as they are being phased out.

Temperature increases due to transmission and waste heat are small but can amount to a substantial fraction of the total temperature increase associated with the lowest emission technologies.

5. Sources of uncertainty

Our central result is that transitions from coal to energy technologies having lower carbon emissions will not substantially influence global climate until more than half a century passes, and that even large transitions are likely to produce modest reductions in future temperatures. These fundamental qualitative conclusions are robust, but our quantitative calculations incorporate important sources of uncertainty in representations of both the energy system and the physical climate system.

We characterize uncertainty in energy system properties by presenting both high and low estimates from life-cycle analyses (e.g., figures 1–3). Our model of the physical climate system is affected by uncertainties both in the relationship between greenhouse gas emissions and atmospheric concentrations and in the relationship between atmospheric concentrations and the resulting climate change. The IPCC [5] states that equilibrium climate sensitivity to a doubling of atmospheric CO_2 content 'is likely to lie between 2 and 4.5 °C with a most likely value of approximately 3 °C.' Our model yields a climate sensitivity of 3.18 °C per CO_2-doubling. Physical climate system uncertainties could thus potentially halve or double our quantitative results. The impact of most of these uncertainties would apply equally to all technologies, however, so relative amounts of warming resulting from different technology choices are likely to be insensitive to uncertainties about the climate system.

6. Conclusions

Here, we have examined energy system transitions on the scale of the existing electricity sector, which generates $\sim$1 TW_e primarily from approximately 3 TW thermal energy from fossil fuels [3]. It has been estimated, however, that 10–30 TW of carbon-neutral thermal energy must be provisioned by mid-century to meet global demand on a trajectory that stabilizes the climate with continued economic growth [1].

It appears that there is no quick fix; energy system transitions are intrinsically slow [13]. During a transition, energy is used both to create new infrastructure and to satisfy other energy demands, resulting in additional emissions. These emissions have a long legacy due to the long lifetime of CO_2 in the atmosphere and the thermal inertia of the oceans. Despite the lengthy time lags involved, delaying rollouts of low-carbon-emission energy technologies risks even greater environmental harm in the second half of this century and beyond. This underscores the urgency in developing realistic plans for the rapid deployment of the lowest-GHG-emission electricity generation technologies. Technologies that offer only modest reductions in emissions, such as natural gas and—if the highest estimates from the life-cycle analyses (SOM table S1 available at stacks.iop.org/ERL/7/014019/mmedia) are correct—carbon capture storage, cannot yield substantial temperature reductions this century. Achieving substantial reductions in temperatures relative to the coal-based system will take the better part of a century, and will depend on rapid and massive deployment of some mix of conservation, wind, solar, and nuclear, and possibly carbon capture and storage.

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Annual Energy Outlook 2013

with Projections to 2040

Independent Statistics & Analysis
U.S. Energy Information Administration

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The *AEO2013* is available on the EIA website at www.eia.gov/forecasts/aeo. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at www.eia.gov/forecasts/aeo/assumptions. Model documentation reports for the National Energy Modeling System are available at website www.eia.gov/analysis/model-documentation.cfm and will be updated for the *AEO2013* during 2013.

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Annual Energy Outlook 2013

With Projections to 2040

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Preface

The *Annual Energy Outlook 2013 (AEO2013)*, prepared by the U.S. Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2040, based on results from EIA's National Energy Modeling System. EIA published an "early release" version of the *AEO2013* Reference case in December 2012.

The report begins with an "Executive summary" that highlights key aspects of the projections. It is followed by a "Legislation and regulations" section that discusses evolving legislative and regulatory issues, including a summary of recently enacted legislation and regulations, such as: Updated handling of the U.S. Environmental Protection Agency's (EPA) National Emissions Standards for Hazardous Air Pollutants for industrial boilers and process heaters [*1*]; New light-duty vehicle (LDV) greenhouse gas (GHG) and corporate average fuel economy (CAFE) standards for model years 2017 to 2025 [*2*]; Reinstatement of the Clean Air Interstate Rule (CAIR) [*3*] after the court's announcement of intent to vacate the Cross-State Air Pollution Rule (CSAPR) [*4*]; and Modeling of California's Assembly Bill 32, the Global Warming Solutions Act (AB 32) [*5*], which allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020.

The "Issues in focus" section contains discussions of selected energy topics, including a discussion of the results in two cases that adopt different assumptions about the future course of existing policies, with one case assuming the elimination of sunset provisions in existing policies and the other case assuming the elimination of the sunset provisions and the extension of a selected group of existing public policies—CAFE standards, appliance standards, and production tax credits. Other discussions include: oil price and production trends in *AEO2013*; U.S. reliance on imported liquids under a range of cases; competition between coal and natural gas in electric power generation; high and low nuclear scenarios through 2040; and the impact of growth in natural gas liquids production.

The "Market trends" section summarizes the projections for energy markets. The analysis in *AEO2013* focuses primarily on a Reference case, Low and High Economic Growth cases, and Low and High Oil Price cases. Results from a number of other alternative cases also are presented, illustrating uncertainties associated with the Reference case projections for energy demand, supply, and prices. Complete tables for the five primary cases are provided in Appendixes A through C. Major results from many of the alternative cases are provided in Appendix D. Complete tables for all the alternative cases are available on EIA's website in a table browser at http://www.eia.gov/oiaf/aeo/tablebrowser.

AEO2013 projections are based generally on federal, state, and local laws and regulations in effect as of the end of September 2012. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections. In certain situations, however, where it is clear that a law or regulation will take effect shortly after the *Annual Energy Outlook (AEO)* is completed, it may be considered in the projection.

AEO2013 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The *Annual Energy Outlook 2013 (AEO2013)* Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in *AEO2013* generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2013* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

Updated *Annual Energy Outlook 2013* Reference case (April 2013)

The *AEO2013* Reference case included as part of this complete report, released in April 2013, was updated from the *AEO2012* Reference case released in June 2012. The Reference case was updated to reflect new legislation or regulation enacted since that time or to incorporate modeling changes. Major changes made in the Reference case include:

- Extension of the projection period through 2040, an additional five years beyond *AEO2012*.
- Adoption of a new Liquid Fuels Market Module (LFMM) in place of the Petroleum Market Module used in earlier *AEO*s provides for more granular and integrated modeling of petroleum refineries and all other types of current and potential future liquid fuels production technologies. This allows more direct analysis and modeling of the regional supply and demand effects involving crude oil and other feedstocks, current and future processes, and marketing to consumers.
- A shift to the use of Brent spot price as the reference oil price. *AEO2013* also presents the average West Texas Intermediate spot price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and includes the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners.
- A shift from using regional natural gas wellhead prices to using representative regional natural gas spot prices as the basis of the natural gas supply price. Due to this change, the methodology for estimating the Henry Hub price was revised.
- Updated handling of data on flex-fuel vehicles (FFVs) to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard, but the phasing out of CAFE credits for their sale and limited demand from consumers reduce their market penetration.
- A revised outlook for industrial production to reflect the impacts of increased shale gas production and lower natural gas prices, which result in faster growth for industrial production and energy consumption. The industries affected include, in particular, bulk chemicals and primary metals.
- Incorporation of a new aluminum process flow model in the industrial sector, which allows for diffusion of technologies through choices made among known commercial and emerging technologies based on relative capital costs and fuel expenditures and provides for a more realistic representation of the evolution of energy consumption than in previous *AEO*s.
- An enhanced industrial chemical model, in several respects: the baseline liquefied petroleum gas (LPG) feedstock data have been aligned with 2006 survey data; use of an updated propane-pricing mechanism that reflects natural gas price influences in order to allow for price competition between LPG feedstock and petroleum-based (naphtha) feedstock; and specific accounting in the Industrial Demand Model for propylene supplied by the LFMM.
- Updated handling of the EPA's National Emissions Standards for Hazardous Air Pollutants for industrial boilers and process heaters to address the maximum degree of emissions reduction using maximum achievable control technology. An industrial capital expenditure and fuel price adjustment for coal and residual fuel has been applied to reflect risk perception about the use of those fuels relative to natural gas.
- Augmentation of the construction and mining models in the Industrial Demand Model to better reflect *AEO2013* assumptions regarding energy efficiencies in off-road vehicles and buildings, as well as the productivity of coal, oil, and natural gas extraction.
- Adoption of final model year 2017 to 2025 GHG emissions and CAFE standards for LDVs, which increases the projected fuel economy of new LDVs to 47.3 mpg in 2025.
- Updated handling of the representation of purchase decisions for alternative fuels for heavy-duty vehicles. Market factors used to calculate the relative cost of alternative-fuel vehicles, specifically natural gas, now represent first buyer-user behavior and slightly longer breakeven payback periods, significantly increasing the demand for natural gas fuel in heavy trucks.
- Updated modeling of LNG export potential, which includes a rudimentary assessment of pricing of natural gas in international markets.
- Updated power generation unit costs that capture recent cost declines for some renewable technologies, which tend to lead to greater use of renewable generation, particularly solar technologies.
- Reinstatement of CAIR after the court's announcement of intent to vacate CSAPR.
- Modeling of California's AB 32, that allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020. The coordinated regulations include an enforceable GHG cap that will decline over time. *AEO2013* reflects all covered sectors, including emissions offsets and allowance allocations.
- Incorporation of the California Low Carbon Fuel Standard, which requires fuel producers and importers who sell motor gasoline or diesel fuel in California to reduce the carbon intensity of those fuels by 10 percent between 2012 and 2020 through the increased sale of alternative low-carbon fuels.

Future analyses using the *AEO2013* Reference case will start from the version of the Reference case released with this complete report.

Endnotes for Preface

Links current as of March 2013

1. U.S. Government Printing Office, “Clean Air Act,” 42 U.S.C. 7412 (Washington, DC: 2011), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title42/pdf/USCODE-2011-title42-chap85-subchapI-partA.pdf.
2. U.S. Environmental Protection Agency and Department of Transportation, National Highway Traffic Safety Administration, “2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule,” *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
3. U.S. Environmental Protection Agency, “Clean Air Interstate Rule (CAIR)” (Washington, DC: December 19, 2012), http://www.epa.gov/cair/index.html#older.
4. U.S. Environmental Protection Agency, “Fact Sheet: The Cross-State Air Pollution Rule: Reducing the Transport of Fine Particulate Matter and Ozone” (Washington, DC: July 2011), http://www.epa.gov/airtransport/pdfs/CSAPRFactsheet.pdf.
5. California Legislative Information, “Assembly Bill No. 32: California Global Warming Solutions Act of 2006” (Sacramento, CA: September 27, 2006), http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf.

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Comparison with other projections

Executive summary

The projections in the U.S. Energy Information Administration's *Annual Energy Outlook 2013 (AEO2013)* focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2013* Reference case provides a basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. *AEO2013* also includes alternative cases (see Appendix E, Table E1), which explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy. Many of the implications of the alternative cases are discussed in the Issues in focus section of *AEO2013*.

Key results highlighted in the *AEO2013* Reference and alternative cases include:

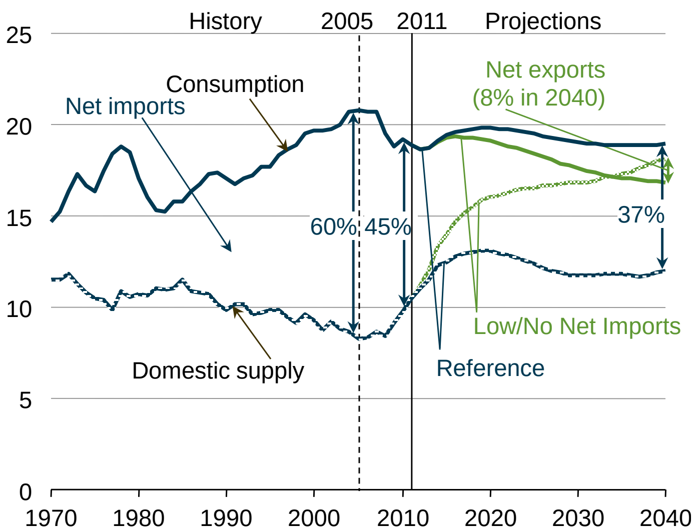
- Continued strong growth in domestic crude oil production over the next decade—largely as a result of rising production from tight formations—and increased domestic production of natural gas;
- The potential for even stronger growth in domestic crude oil production under alternative conditions;
- Evolving natural gas markets that spur increased use of natural gas for electric power generation and transportation and an expanding natural gas export market;
- A decline in motor gasoline consumption over the projection period, reflecting the effects of more stringent corporate average fuel economy (CAFE) standards, as well as growth in diesel fuel consumption and increased use of natural gas to power heavy-duty vehicles; and
- Low electricity demand growth, and continued increases in electricity generation capacity fueled by natural gas and renewable energy, which when combined with environmental regulations put pressure on coal use in the electric power sector. In some cases, coal's share of total electricity generation falls below the natural gas share through the end of the projection period.

Oil production, particularly from tight oil plays, rises over the next decade, leading to a reduction in net import dependence

Crude oil production has increased since 2008, reversing a decline that began in 1986. From 5.0 million barrels per day in 2008, U.S. crude oil production increased to 6.5 million barrels per day in 2012. Improvements in advanced crude oil production technologies continues to lift domestic supply, with domestic production of crude oil increasing in the Reference case before declining gradually beginning in 2020 for the remainder of the projection period. The projected growth results largely from a significant increase in onshore crude oil production, particularly from shale and other tight formations, which has been spurred by technological advances and relatively high oil prices. Tight oil development is still at an early stage, and the outlook is highly uncertain. In some of the *AEO2013* alternative cases, tight oil production and total U.S. crude oil production are significantly above their levels in the Reference case.

The net import share of U.S. petroleum and other liquids consumption (including crude oil, petroleum liquids, and liquids derived from nonpetroleum sources) grew steadily from the mid-1980s to 2005 but has fallen in every year since then (Figure 1). In the Reference case, U.S. net imports of petroleum and other liquids decline through 2019, while still providing approximately one-third of total U.S. supply. The net import share of U.S. petroleum and other liquids consumption continues to decline in the Reference case, falling to 34 percent in 2019 before increasing to 37 percent in 2040.

Figure 1. Net import share of U.S. liquids supply in two cases, 1970-2040 (million barrels per day)



The U.S. could become a net exporter of liquid fuels under certain conditions. An article in the Issues in focus section considers four cases that examine the impacts of various assumptions about U.S. dependence on imported liquids. Two cases (Low Oil and Gas Resource and High Oil and Gas Resource) vary only the supply assumptions, and two cases (Low/No Net Imports and High Net Imports) vary both the supply and demand assumptions. The different assumptions in the four cases generate wide variation from the liquid fuels import dependence values in the *AEO2013* Reference case. In the Low/No Net Imports case, the United States ends its reliance on net imports of liquid fuels in the mid-2030s, with net exports rising to 8 percent of total U.S. liquid fuel production in 2040. In contrast, in the High Net Imports case, net petroleum import dependence is above 44 percent in 2040, which is higher than the Reference case level of 37 percent but still well below the 2005 level of 60 percent.

While other combinations of assumptions or unforeseen technology breakthroughs might produce a comparable outcome, the assumptions in the Low/No Imports case illustrate the magnitude and type of changes that would be required for the United States to end its reliance on net imports of liquid fuels, which began after World War II and has continued to the present day. Some of the assumptions in the Low/No Net Imports case, such as increased fuel economy for light-duty vehicles (LDVs) after 2025 and wider access to offshore resources, could be influenced by possible future energy policies. However, other assumptions in this case, such as the greater availability of onshore technically recoverable oil and natural gas resources, depend on geological outcomes that cannot be influenced by policy measures. In addition, economic trends, consumer preferences and behaviors, and technological factors also may be unaffected, or only modestly affected, by policy measures.

In the High Oil and Gas Resource case, changes due to the supply assumptions alone cause net import dependence to decline to 7 percent in 2040, with U.S. crude oil production rising to 10.2 million barrels per day in 2040, or 4.1 million barrels per day above the Reference case level. Tight oil production accounts for more than 77 percent (or 3.2 million barrels per day) of the difference in production between the two cases. Production of natural gas plant liquids in the United States also exceeds the Reference case level.

One of the most uncertain aspects of this analysis is the potential effect of different scenarios on the global market for liquid fuels, which is highly integrated. Strategic choices made by leading oil-exporting countries could result in U.S. price and quantity changes that differ significantly from those presented here. Moreover, regardless of how much the United States reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices if current policies and regulations remain in effect and world markets for delivery continue to be competitive.

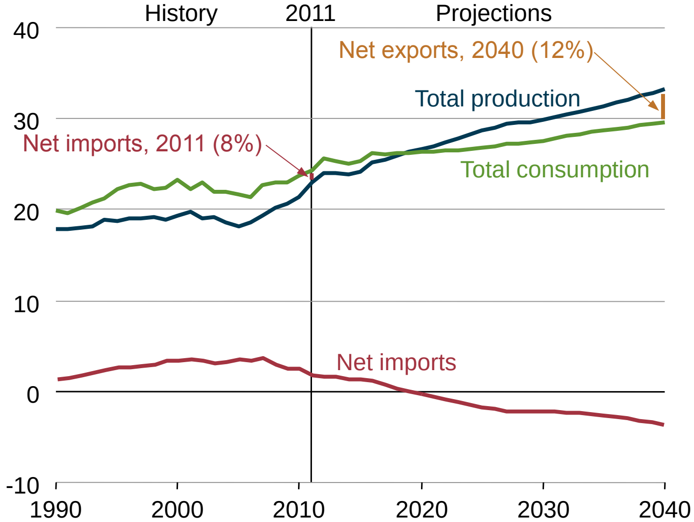
The United States becomes a net exporter of natural gas

U.S. dry natural gas production increases 1.3 percent per year throughout the Reference case projection, outpacing domestic consumption by 2019 and spurring net exports of natural gas (Figure 2). Higher volumes of shale gas production are central to higher total production volumes and a transition to net exports. As domestic supply has increased in recent years, natural gas prices have declined, making the United States a less attractive market for imported natural gas and more attractive for export.

U.S. net exports of natural gas grow to 3.6 trillion cubic feet in 2040 in the Reference case. Most of the projected growth in U.S. exports consists of pipeline exports to Mexico, which increase steadily as growing volumes of imported natural gas from the United States fill the widening gap between Mexico's production and consumption. Declining natural gas imports from Canada also contribute to the growth in U.S. net exports. Net U.S. imports of natural gas from Canada decline sharply from 2016 to 2022, then stabilize somewhat before dropping off again in the final years of the projection, as continued growth in domestic production mitigates the need for imports.

Continued low levels of liquefied natural gas (LNG) imports in the projection period, combined with increased U.S. exports of domestically sourced LNG, position the United States as a net exporter of LNG by 2016. U.S. exports of domestically sourced LNG (excluding exports from the existing Kenai facility in Alaska) begin in 2016 and rise to a level of 1.6 trillion cubic feet per year in 2027. One-half of the U.S. exports of LNG originate from the Lower 48 states and the other half from Alaska. The prospects for exports are highly uncertain, however, depending on many factors that are difficult to gauge, such as the development of new production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic. In addition, future U.S. exports of LNG depend on a number of other factors, including the speed and extent of price convergence in global natural gas markets and the extent to which natural gas competes with liquids in domestic and international markets.

Figure 2. Total U.S. natural gas production, consumption, and net imports in the Reference case, 1990-2040 (trillion cubic feet)



In the High Oil and Gas Resource case, with more optimistic resource assumptions, U.S. LNG exports grow to more than 4 trillion cubic feet in 2040. Most of the additional exports originate from the Lower 48 states.

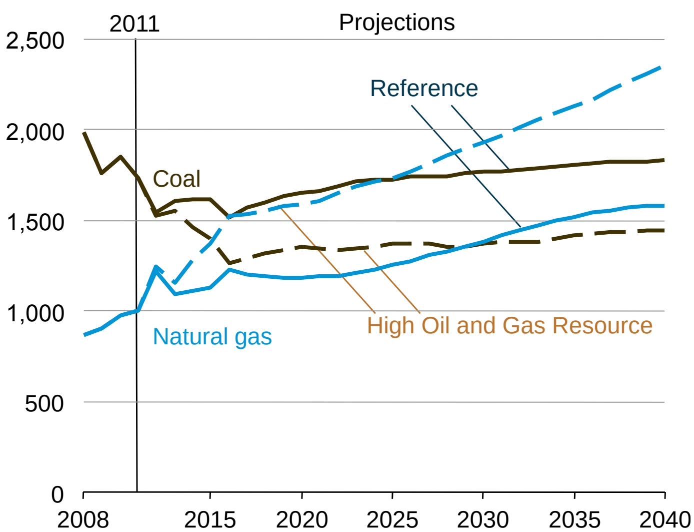
Coal's share of electric power generation falls over the projection period

Although coal is expected to continue its important role in U.S. electricity generation, there are many uncertainties that could affect future outcomes. Chief among them are the relationship between coal and natural gas prices and the potential for policies aimed at reducing greenhouse gas (GHG) emissions. In 2012, natural gas prices were low enough for a few months for power companies to run natural gas-fired generation plants more economically than coal plants in many areas. During those months, coal and natural gas were nearly tied in providing the largest share of total electricity generation, something that had never happened before. In the Reference case, existing coal plants recapture some of the market they recently lost to natural gas plants because natural gas prices rise more rapidly than coal prices. However, the rise in coal-fired generation is not sufficient for coal to maintain its generation share, which falls to 35 percent by 2040 as the share of generation from natural gas rises to 30 percent.

In the alternative High Oil and Natural Gas Resource case, with much lower natural gas prices, natural gas supplants coal as the top source of electricity generation (Figure 3). In this case, coal accounts for only 27 percent of total generation in 2040, while natural gas accounts for 43 percent. However, while natural gas generation in the power sector surpasses coal generation in 2016 in this case, more coal energy than natural gas energy is used for power generation until 2035 because of the higher average thermal efficiency of the natural gas-fired generating units. Coal use for electric power generation falls to 14.7 quadrillion Btu in 2040 in the High Oil and Natural Gas Resource case (compared with 18.7 quadrillion Btu in the Reference case), while natural gas use rises to 15.1 quadrillion Btu in the same year (Figure 4). Natural gas use for electricity generation is 9.7 quadrillion Btu in 2040 in the Reference case.

Coal's generation share and the associated carbon dioxide (CO_2) emissions could be further reduced if policies aimed at reducing GHG emissions were enacted (Figure 5). For example, in the GHG15 case, which assumes a fee on CO_2 emissions that starts at $15 per metric ton in 2014 and increases by 5 percent per year through 2040, coal's share of total generation falls to 13 percent in 2040. Energy-related CO_2 emissions also fall sharply in the GHG15 case, to levels that are 10 percent, 15 percent, and 24 percent lower than projected in the Reference case in 2020, 2030, and 2040, respectively. In 2040, energy-related CO_2 emissions in the GHG15 case are 28 percent lower than the 2005 total. In the GHG15 case, coal use in the electric power sector falls to only 6.1 quadrillion Btu in 2040, a decline of about two-thirds from the 2011 level. While natural gas use in the electric power sector initially displaces coal use in this case, reaching more than 10 quadrillion Btu in 2016, it falls to 8.8 quadrillion Btu in 2040 as growth in renewable and nuclear generation offsets natural gas use later in the projection period.

Figure 3. Electricity generation from coal and natural gas in two cases, 2008-2040 (billion kilowatthours)



With more efficient light-duty vehicles, motor gasoline consumption declines while diesel fuel use grows, even as more natural gas is used in heavy-duty vehicles

The *AEO2013* Reference case incorporates the GHG and CAFE standards for LDVs [6] through the 2025 model year. The increase in vehicle efficiency reduces LDV energy use from 16.1 quadrillion Btu in 2011 to 14.0 quadrillion Btu in 2025, predominantly motor gasoline (Figure 6). LDV energy use continues to decline through 2036, then levels off until 2039 as growth in population and vehicle miles traveled offsets more modest improvement in fuel efficiency.

Figure 4. Coal and natural gas use in the electric power sector in three cases, 2011, 2025, and 2040 (quadrillion Btu)

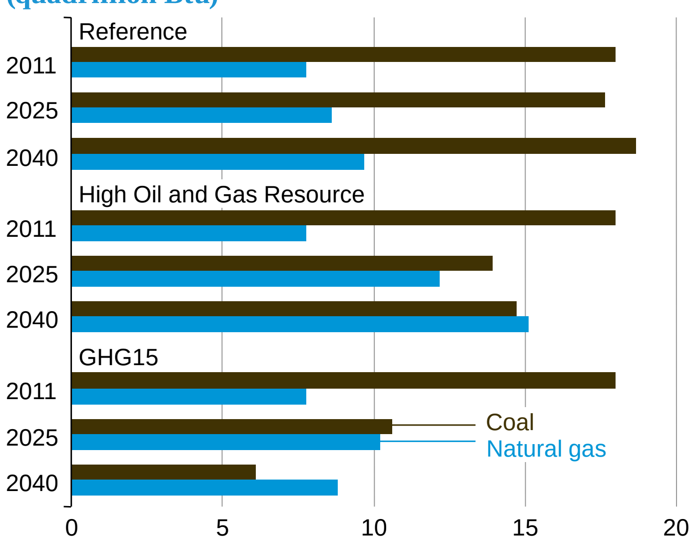
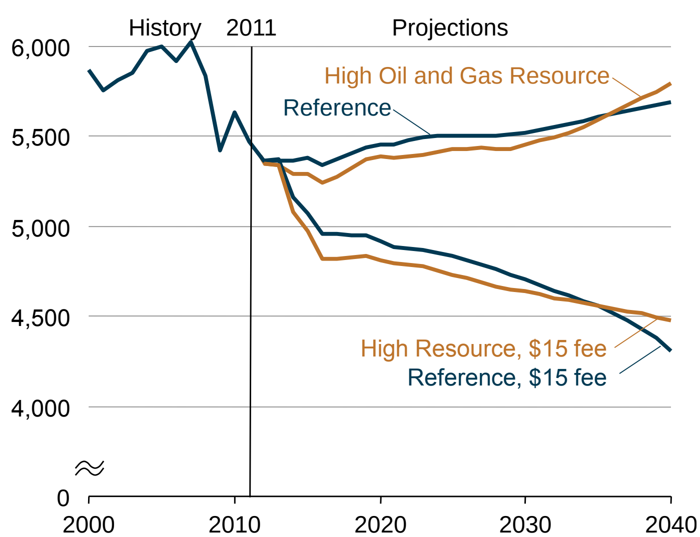


Figure 5. Energy-related carbon dioxide emissions in four cases, 2000-2040 (million metric tons)



Furthermore, the improved economics of natural gas as a fuel for heavy-duty vehicles result in increased use that offsets a portion of diesel fuel consumption. The use of petroleum-based diesel fuel is also reduced by growing consumption of diesel produced with gas-to-liquids (GTL) technology. Natural gas use in vehicles (including natural gas used in the production of GTL) totals 1.4 trillion cubic feet in 2040 in the Reference case, displacing 0.7 million barrels per day of other motor fuels [7]. Diesel fuel use nonetheless increases at a relatively strong rate, with freight travel demand supported by increasing industrial production.

Natural gas consumption grows in industrial and electric power sectors as domestic production also serves an expanding export market

Relatively low natural gas prices, maintained by growing shale gas production, spur increased use in the industrial and electric power sectors, particularly over the next decade. In the Reference case, natural gas use in the industrial sector increases by 16 percent, from 6.8 trillion cubic feet per year in 2011 to 7.8 trillion cubic feet per year in 2025. After 2025, the growth of natural gas consumption in the industrial sector slows, while total U.S. consumption continues to grow (Figure 7). This additional growth is mostly for use in the electric power sector. Although natural gas continues to capture a growing share of total electricity generation, natural gas consumption by power plants does not increase as sharply as generation because new plants are very efficient (needing less fuel per unit of power output). The natural gas share of generation rose from 16 percent of generation in 2000 to 24 percent in 2011 and increases to 27 percent in 2025 and 30 percent in 2040. Natural gas use in the residential and commercial sectors remains nearly constant, as increasing end-use demand is balanced by increasing end-use efficiency.

Natural gas consumption also grows in other markets in the Reference case, including heavy-duty freight transportation (trucking) and as a feedstock for GTL production of diesel and other fuels. Those uses account for 6 percent of total U.S. natural gas consumption in 2040, as compared with almost nothing in 2011.

Natural gas use in the electric power sector grows even more sharply in the High Oil and Natural Gas Resource case, as the natural gas share of electricity generation grows to 39 percent, reaching 14.8 trillion cubic feet in 2040, more than 55 percent greater than in the Reference case. Industrial sector natural gas consumption growth is also stronger in this case, with growth continuing after 2025 and reaching 13.0 trillion cubic feet in 2040 (compared to 10.5 trillion cubic feet in 2040 in the Reference case). Much of the industrial growth in the High Oil and Natural Gas Resource case is associated with natural gas use for GTL production and increased lease and plant use in natural gas production.

Renewable fuel use grows at a faster rate than fossil fuel use

The share of U.S. electricity generation from renewable energy grows from 13 percent in 2011 to 16 percent in 2040 in the Reference case. Electricity generation from solar and, to a lesser extent, wind energy sources grows as their costs decline, making them more economical in the later years of the projection. However, the rate of growth in renewable electricity generation is sensitive to several factors, including natural gas prices and the possible implementation of policies to reduce GHG emissions. If future natural gas prices are lower than projected in the Reference case, as illustrated in the High Oil and Gas Resource case, the share of renewable generation would grow more slowly, to only 14 percent in 2040. Alternatively, if broad-based policies to reduce GHG emissions were enacted, renewable generation would be expected to grow more rapidly. In three cases that assume GHG emissions fees that range from $10 to $25 per metric ton in 2014 and rise by 5 percent per year through 2040 (GHG10, GHG15, and GHG25), the

Figure 6. Transportation energy consumption by fuel, 1990-2040 (quadrillion Btu)

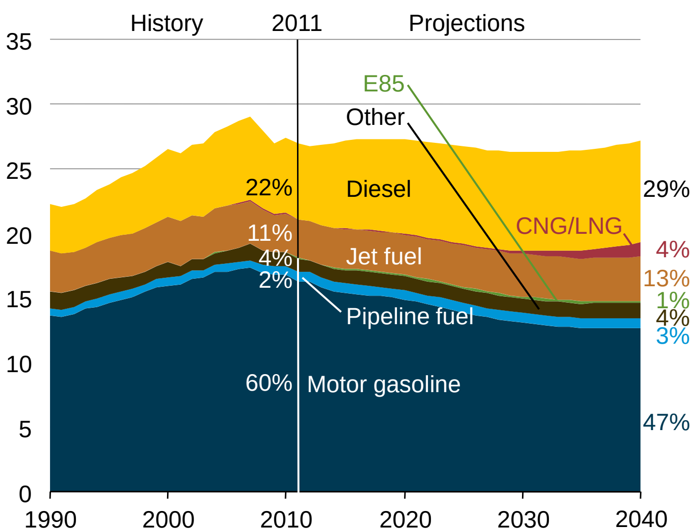


Figure 7. U.S. dry natural gas consumption by sector, 2005-2040 (trillion cubic feet)

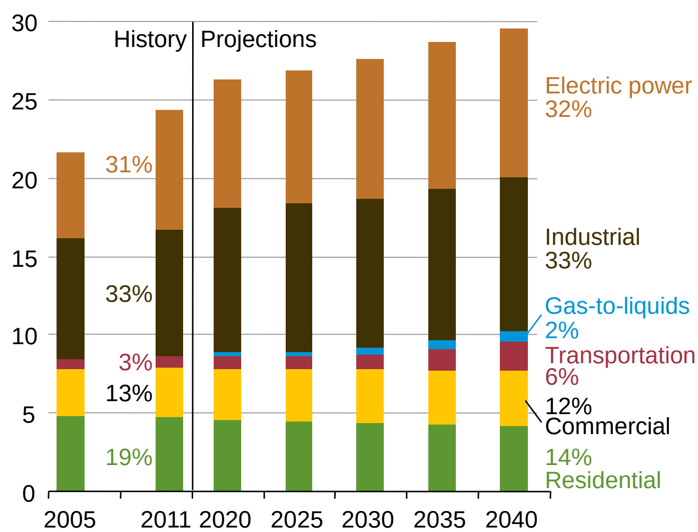
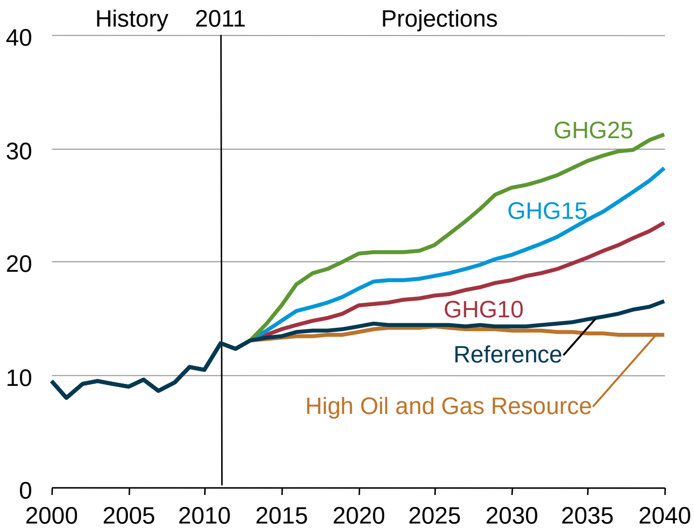


Figure 8. Renewable energy share of U.S. electricity generation in five cases, 2000-2040 (percent)



renewable share of total U.S. electricity generation in 2040 ranges from 23 percent to 31 percent (Figure 8).

The *AEO2013* Reference case reflects a less optimistic outlook for advanced biofuels to capture a rapidly growing share of the liquid fuels market than earlier *Annual Energy Outlooks*. As a result, biomass use in the Reference case totals 5.9 quadrillion Btu in 2035 and 7.1 quadrillion Btu in 2040, up from 4.0 quadrillion Btu in 2011.

Endnotes for Executive summary

Links current as of March 2013

6. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards," *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
7. Liquid motor fuels include diesel and liquid fuels from gas-to-liquids (GTL) processes. Liquid fuel volumes from GTL for motor vehicle use are estimated based on the ratio of onroad diesel and gasoline to total diesel and gasoline.

Legislation and regulations

Introduction

The *Annual Energy Outlook 2013 (AEO2013)* generally represents current federal and state legislation and final implementation regulations as of the end of September 2012. The *AEO2013* Reference case assumes that current laws and regulations affecting the energy sector are largely unchanged throughout the projection period (including the implication that laws that include sunset dates are no longer in effect at the time of those sunset dates) [*8*]. The potential impacts of proposed legislation, regulations, or standards—or of sections of authorizing legislation that have been enacted but are not funded or where parameters will be set in a future regulatory process—are not reflected in the *AEO2013* Reference case, but some are considered in alternative cases. The *AEO2013* Reference case does not reflect the provisions of the American Taxpayer Relief Act of 2012 (P.L. 112-240) enacted on January 1, 2013 [*9*]. Key energy-related provisions of that legislation—including extension of the production tax credit for renewable generation, tax credits for energy-efficient appliances, and tax credits for selected biofuels—are reflected in an alternative case completed as part of *AEO2013*. This section summarizes federal and state legislation and regulations newly incorporated or updated in *AEO2013* since the completion of the *Annual Energy Outlook 2012 (AEO2012)*.

Examples of federal and state legislation and regulations incorporated in the *AEO2013* Reference case or whose handling has been modified include:

- Incorporation of new light-duty vehicle greenhouse gas emissions (GHG) and corporate average fuel economy (CAFE) standards for model years 2017 to 2025 [*10*]
- Continuation of the Clean Air Interstate Rule (CAIR) [*11*] after the court's announcement of intent to vacate the Cross-State Air Pollution Rule (CSAPR) [*12*]
- Updated handling of the U.S. Environmental Protection Agency's (EPA) National Emissions Standards for Hazardous Air Pollutants (NESHAP) for industrial boilers and process heaters [*13*]
- Modeling of California's Assembly Bill 32, the Global Warming Solutions Act (AB 32) [*14*], that allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020
- Incorporation of the California Low Carbon Fuel Standard (LCFS) [*15*], which requires fuel producers and importers who sell motor gasoline or diesel fuel in California to reduce the carbon intensity of those fuels by an average of 10 percent between 2012 and 2020 through the mixing and increased sale of alternative low-carbon fuels.

There are many other pieces of legislation and regulation that appear to have some probability of being enacted in the not-too-distant future, and some laws include sunset provisions that may be extended. However, it is difficult to discern the exact forms that the final provisions of pending legislation or regulations will take, and sunset provisions may or may not be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. Many pending provisions are examined in alternative cases included in *AEO2013* or in other analyses completed by the U.S. Energy Information Administration (EIA). In addition, at the request of the Administration and Congress, EIA has regularly examined the potential implications of other possible energy options in Service Reports. Those reports can be found on the EIA website at http://www.eia.gov/oiaf/service_rpts.htm.

1. Greenhouse gas emissions and corporate average fuel economy standards for 2017 and later model year light-duty vehicles

On October 15, 2012, EPA and the National Highway Traffic Safety Administration (NHTSA) jointly issued a final rule for tailpipe emissions of carbon dioxide (CO_2) and CAFE standards for light-duty vehicles, model years 2017 and beyond [*16*]. EPA, operating under powers granted by the Clean Air Act (CAA), issued final CO_2 emissions standards for model years 2017 through 2025 for passenger cars and light-duty trucks, including medium-duty passenger vehicles. NHTSA, under powers granted by the Energy Policy and Conservation Act, as amended by the Energy Independence and Security Act, issued CAFE standards for passenger cars and light-duty trucks, including medium-duty passenger vehicles, for model years 2017 through 2025.

The new CO_2 emissions and CAFE standards will first affect model year 2017 vehicles, with compliance requirements increasing in stringency each year thereafter through model year 2025. EPA has established standards that are expected to require a fleet-wide average of 163 grams CO_2 per mile for light-duty vehicles in model year 2025, which is equivalent to a fleet-wide average of 54.5 miles per gallon (mpg) if reached only through fuel economy. However, the CO_2 emissions standards can be met in part through reductions in air-conditioning leakage and the use of alternative refrigerants, which reduce CO_2-equivalent GHG emissions but do not affect the estimation of fuel economy compliance in the test procedure.

NHTSA has established two phases of CAFE standards for passenger cars and light-duty trucks (Table 1). The first phase, covering model years 2017 through 2021, includes final standards that NHTSA estimates will result in a fleet-wide average of 40.3 mpg for light-duty vehicles in model year 2021 [*17*]. The second phase, covering model years 2022 through 2025, requires additional improvements leading to a fleet-wide average of 48.7 mpg for light-duty vehicles in model year 2025. Compliance with CO_2 emission and CAFE standards is calculated only after final model year vehicle production, with fleet-wide light-duty vehicle standards representing averages based on the sales volume of passenger cars and light-duty trucks for a given year. Because sales volumes are not known until after the end of the model year, EPA and NHTSA estimate future fuel economy based on the projected sales volumes of passenger cars and light-duty trucks.

The new CO_2 emissions and CAFE standards for passenger cars and light-duty trucks use an attribute-based standard that is determined by vehicle footprint—the same methodology that was used in setting the final rule for model year 2012 to 2016 light-duty vehicles. Footprint is defined as wheelbase size (the distance from the center of the front axle to the center of the rear axle), multiplied by average track width (the distance between the center lines of the tires) in square feet. The minimum requirements for CO_2 emissions and CAFE are production-weighted averages based on unique vehicle footprints in a manufacturer's fleet and are calculated separately for passenger cars and light-duty trucks (Figures 9 and 10), reflecting their different design capabilities. In general, as vehicle footprint increases, compliance requirements decline to account for increased vehicle size and load-carrying capability. Each manufacturer faces a unique combination of CO_2 emission and CAFE standards, depending on the number of vehicles produced and the footprints of those vehicles, separately for passenger cars and light-duty trucks.

For passenger cars, average fleet-wide compliance levels increase in stringency by 3.9 percent annually between model years 2017 and 2021 and by 4.7 percent annually between 2022 and 2025, based on the model year 2010 baseline fleet. In recognition of the challenge of improving the fuel economy and reducing CO_2 emissions of full-size pickup trucks while maintaining towing and payload capabilities, the average annual rate of increase in the stringency of light-duty truck standards is 2.9 percent from 2017 to 2021, with smaller light-duty trucks facing higher increases and larger light-duty trucks lower increases in compliance stringency. From 2022 to 2025, the average annual increase in compliance stringency for all light-duty trucks is 4.7 percent.

The CO_2 emissions and CAFE standards also include flexibility provisions for compliance by individual manufacturers, such as: (1) credit averaging, which allows credit transfers between a manufacturer's passenger car and light-duty truck fleets; (2) credit banking, which allows manufacturers to "carry forward" credits earned from exceeding the standards in earlier model years and to "carry back" credits earned in later model years to offset shortfalls in earlier model years; (3) credit trading between manufacturers who exceed their standards and those who do not; (4) air conditioning improvement credits that can be applied toward CO_2 emissions standards; (5) off-cycle credits for measurable improvements in CO_2 emissions and fuel economy that are not captured by the two-cycle test procedure used to measure emissions and fuel consumption; (6) CO_2 emissions "compliance multipliers" for electric, plug-in hybrid electric, compressed natural gas, and fuel cell vehicles through model year 2021; and (7) incentives for the use of hybrid electric and other advanced technologies in full-size pickup trucks.

Finally, flexibility provisions do not allow domestic passenger cars to deviate significantly from annual fuel economy targets. NHTSA retains a required minimum fuel economy level for

Table 1. NHTSA projected average fleet-wide CAFE compliance levels (miles per gallon) for passenger cars and light-duty trucks, model years 2017-2025, based on the model year 2010 baseline fleet

Model year	Passenger cars	Light-duty trucks	Combined
2017	39.6	29.1	35.1
2018	41.1	29.6	36.1
2019	42.5	30.0	37.1
2020	44.2	30.6	38.3
2021	46.1	32.6	40.3
2022	48.2	34.2	42.3
2023	50.5	35.8	44.3
2024	52.9	37.5	46.5
2025	55.3	39.3	48.7

Figure 9. Projected average passenger car CAFE compliance targets (miles per gallon) by vehicle footprint (square feet), model years 2017-2025

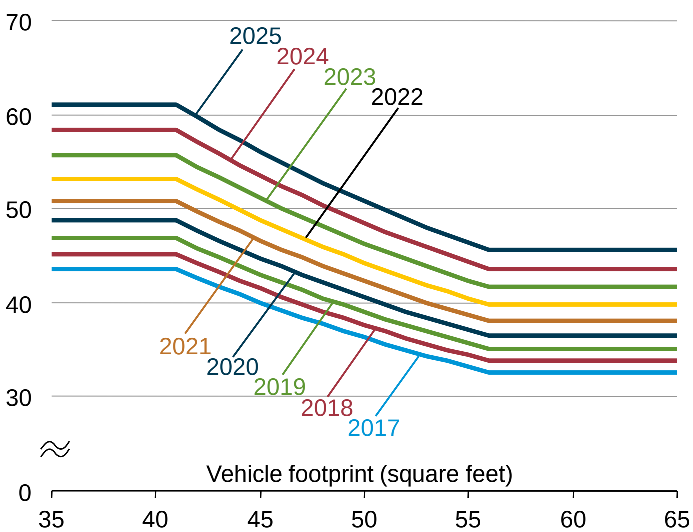
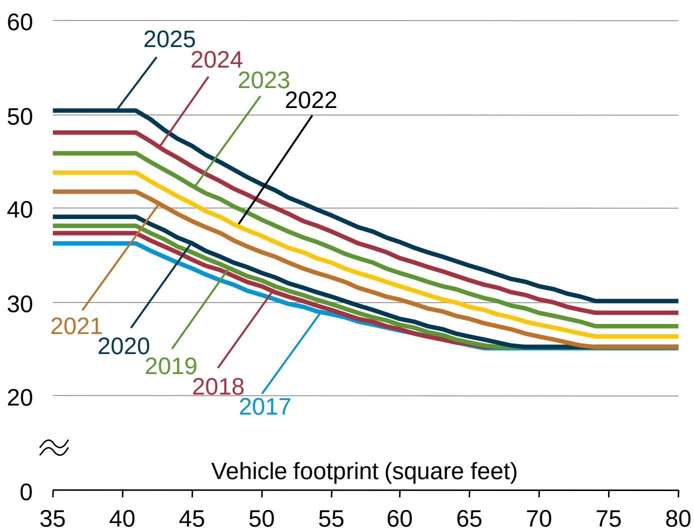


Figure 10. Projected average light-duty truck CAFE compliance targets (miles per gallon) by vehicle footprint (square feet), model years 2017-2025



domestically produced passenger cars by manufacturer that is the higher of 27.5 miles per gallon or 92 percent of the average fuel economy projected for the combined fleet of domestic and foreign passenger cars for sale in the United States. For example, the minimum standard for passenger cars sold by a manufacturer in 2025 would be 50.9 miles per gallon, based on the estimated fleet average passenger car fuel economy for that year.

The *AEO2013* Reference case includes the final CAFE standards for model years 2012 through 2016 (promulgated in March 2010) [*18*] and the standards for model years 2017 through 2025, with subsequent CAFE standards for years 2026-2040 vehicles calculated using 2025 levels of stringency. The *AEO2013* Reference case projects fuel economy values for passenger cars, light-duty trucks, and combined light-duty vehicles that differ from NHTSA projections. This variance is the result of a different distribution of the production of passenger cars and light-duty trucks by footprint as well as a different mix between passenger cars and light-duty trucks (Table 2). CAFE standards are included by using the equations and coefficients employed by NHTSA to determine unique fuel economy requirements based on footprint, along with the ability of manufacturers to earn flexibility credits toward compliance. The *AEO2013* Reference case projects sales of passenger cars and light-duty trucks by vehicle footprint with the key assumption that vehicle footprints are held constant by manufacturer in each light-duty vehicle size class.

2. Recent rulings on the Cross-State Air Pollution Rule and the Clean Air Interstate Rule

On August 21, 2012, the United States Court of Appeals for the District of Columbia Circuit announced its intent to vacate CSAPR, which it had stayed from going into effect earlier in 2012. CSAPR was to replace CAIR, which was in effect, by establishing emissions caps (levels) for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from power plants in the eastern half of the United States. As a result of the court's action, the regulation of SO_2 and NO_X emissions will continue to be administered under CAIR pending the promulgation of a valid replacement. *AEO2013* assumes that CAIR remains a binding regulation through 2040.

CAIR covers all fossil-fueled power plant units with nameplate capacity greater than 25 megawatts in 27 eastern states and the District of Columbia (Figure 11). Twenty-two states and the District of Columbia fall under the caps for both annual emissions of SO_2 and NO_X and ozone season NO_X. Three states are controlled for only ozone season NO_X, and two states are controlled for only annual SO_2 and NO_X emissions. The caps went into effect for NO_X in 2009 and for SO_2 in 2010. Both caps are scheduled to be tightened again in 2015. *AEO2013* considered how the power sector would use the emissions allowance trading that EPA set up to lower compliance costs, including capturing the interplay of the SO_2 program for acid rain under the Clean Air Act Amendments Title IV and the CAIR program that uses the same allowances.

Although CSAPR shared some basic similarities with CAIR, there are key differences between the two programs. Generally, CSAPR had greater limitations on trading to ensure that emissions reductions would occur in all states; lower emissions caps; and more rapid phasing in of tighter emissions caps. CSAPR also did not allow carryover of banked allowances from the Acid Rain SO_2 and NO_X Budget programs. Each program was aimed at substantial reductions of power sector SO_2 and NO_X emissions.

AEO2013 represents the limits on SO_2 and NO_X emissions trading as specified by CAIR. The National Energy Modeling System (NEMS) includes the representation of emissions for both the CAIR and non-CAIR regions. In NEMS, power plants in both regions are required to submit allowances to account for their emissions as if covered by the rule. NEMS allows for power plants in the CAIR regions to trade SO_2 allowances with those plants in the non-CAIR region, but the SO_2 allowances are valued differently for each region. NEMS also allows for the banking of SO_2 and NO_X allowances consistent with CAIR's provisions.

3. Nuclear waste disposal and the Waste Confidence Rule

Waste confidence is defined by the U.S. Nuclear Regulatory Commission (NRC) as a finding that spent nuclear fuel can be safely stored for decades beyond the licensed operating life of a reactor without significant environmental effects [*19*]. It enables the NRC to license reactors or renew their licenses without examining the effects of extended waste storage for each individual site pending ultimate disposal.

NRC's Waste Confidence Rule issued in August 1984 [*20*] included five findings:

1. Spent nuclear fuel can be disposed of safely in a mined geologic repository.
2. A mined geologic repository will be available when needed for disposal of spent nuclear fuel.
3. Until a mined geologic repository is available, spent nuclear fuel can be safely managed.
4. Spent nuclear fuel can be safely stored at reactors for 30 years without significant environmental impacts.
5. Storage will be made available for spent nuclear fuel onsite or offsite, if required.

Table 2. *AEO2013* projected average fleet-wide CAFE compliance levels (miles per gallon) for passenger cars and light-duty trucks, model years 2017-2025

Model year	Passenger cars	Light-duty trucks	Combined
2017	40.1	30.1	34.7
2018	40.9	30.7	35.5
2019	42.6	30.9	36.4
2020	44.4	32.0	37.9
2021	46.4	33.8	39.8
2022	48.7	34.9	41.5
2023	51.3	36.5	43.6
2024	52.5	38.3	45.2
2025	55.0	40.0	47.3
2026-2040	Projected stringency based on 2025 levels.		

The Waste Confidence Rule was updated in 1990 [*21*], reviewed in 1999, and updated again in 2010 [*22*].

In December 2010, with the termination of the repository program at Yucca Mountain, the Waste Confidence Rule was amended to state that spent nuclear fuel could be stored safely at reactor sites for 60 years following reactor shutdown. In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit struck down the NRC's 2010 amendment of the Waste Confidence Rule, stating that the NRC should have analyzed the environmental consequences of never building a permanent waste repository, and that the discussion of potential leaks or fires at spent fuel pools was inadequate [*23*].

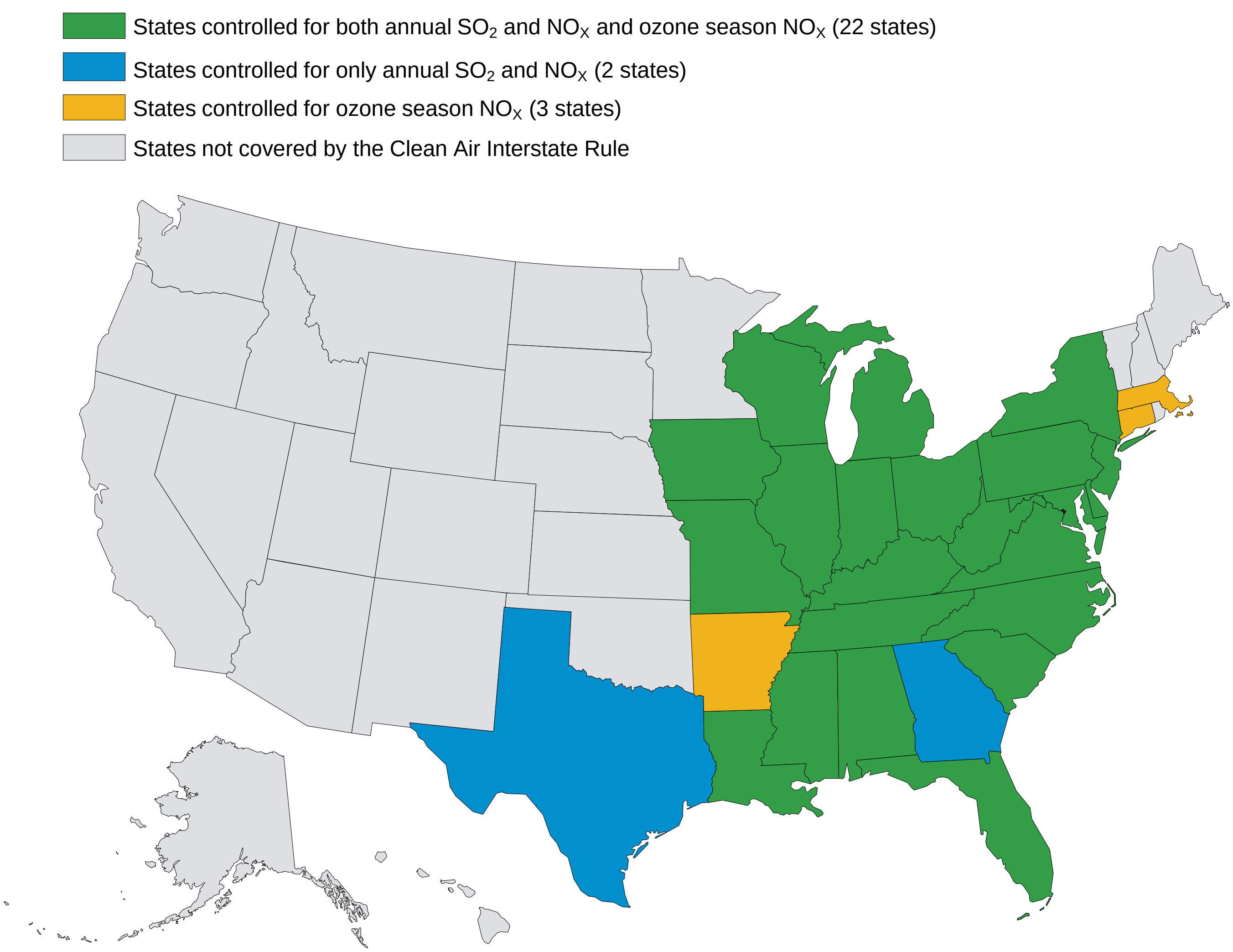
The NRC issued an order in August 2012 that suspended actions related to issuance of operating licenses and license renewals [*24*]. Currently, the NRC is analyzing the potential impacts on licensing reviews and developing a proposed path forward to meet the court's requirements. Until the NRC revises the Waste Confidence Rule, it will not issue reactor operating licenses or operating license renewals. Licensing reviews and proceedings will continue, but Atomic Safety and Licensing Board hearings will be suspended pending further NRC guidance. NRC expects to issue a revised Waste Confidence Rule within 2 years [*25*].

Reactors with license renewal applications under review by the NRC may continue to operate, even if their existing licenses expire, until the NRC can resolve the waste confidence issue and promulgate a revised rule. The regulation states: "If the licensee of a nuclear power plant licensed under 10 CFR 50.21(b) or 50.22 files a sufficient application for renewal of either an operating license or a combined license at least 5 years before the expiration of the existing license, the existing license will not be deemed to have expired until the application has been finally determined" [*26*]. There are currently 15 reactors with license renewal applications in various stages of review by the NRC that are subject to the August 2012 order that suspends licensing decisions.

For those reactors that have not submitted applications for license renewal, the first license expiration date would occur in 2020. Because it is anticipated by the NRC that the issues with the Waste Confidence Rule will be resolved within 2 years, well before 2020, the continued operation of those reactors should not be affected. The *AEO2013* Reference case assumes plants that have not submitted applications for license renewal will be unaffected.

Currently, utilities have the option to license reactors under either of two NRC rules. The NRC's Domestic Licensing of Production and Utilization Facilities rule defines a two-step process for obtaining an operating license [*27*]. First, a construction permit is

Figure 11. States covered by CAIR limits on emissions of sulfur dioxide and nitrogen oxides



issued, and then an operating license is issued. There are two U.S. reactors with current construction permits: Bellefonte Unit 1 and Watts Bar Unit 2. Both plants are owned by the Tennessee Valley Authority (TVA), which has announced that construction of Bellefonte Unit 1 will not proceed until fuel loading at Watts Bar Unit 2 is completed [*28*]. Neither reactor will be able to receive an operating license until the waste confidence issue is resolved, but construction may continue. TVA has not provided a projected date for commencement of operations at Bellefonte Unit 1, but it is unlikely that resolution of the issues associated with the Waste Confidence Rule will affect the operational date of Bellefonte Unit 1. Watts Bar Unit 2 was originally scheduled to go online in 2012, but delays in construction make it unlikely that it will be ready to begin operation before the issues with the Waste Confidence Rule can be resolved. *AEO2013* assumes that Watts Bar Unit 2 will come online in December 2015.

The NRC's "Licenses, Certifications, and Approvals for Nuclear Power Plants" rule defines a one-step process, whereby the construction permit and operating license are issued as a combined license (COL) [*29*]. Once an application for a COL is submitted, the utility may engage in certain pre-construction activities. To date, two plants, each with two reactors, have received COLs in 2012. Vogtle Units 3 and 4 and Summer Units 2 and 3 will both be unaffected by the issues with the Waste Confidence Rule. Once construction and all inspections are complete, the Vogtle and Summer plants may commence operations. For utilities that have submitted applications but have not received COLs, issuance of those licenses may be delayed. For COL applications currently under active review, it is possible that two—Levy County Units 1 and 2 and William States Lee III Units 1 and 2—may be delayed, based on their review status and the NRC's schedule for application reviews. The online dates for the units should be unaffected if issues with the Waste Confidence Rule are resolved within the next 2 years.

Based on EIA's analysis of the Waste Confidence Rule and ongoing proceedings, the *AEO2013* Reference case assumes that the issuance of new operating licenses will not be affected. *AEO2013* also assumes that the Waste Confidence Rule will not affect power uprates, because uprates do not increase the amount of spent nuclear fuel requiring storage, as confirmed in a public policy statement issued by the NRC [*30*].

4. Maximum Achievable Control Technology for industrial boilers

Section 112 of the CAA requires the regulation of air toxics through implementation of NESHAP for industrial, commercial, and institutional boilers [*31*]. The final regulations are also known as "Boiler MACT," where MACT is the Maximum Achievable Control Technology. Pollutants covered by the Boiler MACT regulations include control of hazardous air pollutants (HAPs), such as hydrogen chloride, mercury (Hg), and dioxin/furan, as well as carbon monoxide (CO), and particulate matter (PM) as surrogates for other HAPs. Boilers used for generating electricity are explicitly covered by the Mercury and Air Toxics Standards, also under Section 112 of the CAA, and are specifically excluded from Boiler MACT regulations.

The Final Rule for Boiler MACT was issued in March 2011; a partial Reconsideration Rule concerning limited technical corrections to the Final Rule was issued in December 2011, but it did not replace the Final Rule. The *AEO2013* Reference case assumes that the Final Rule and the partial Reconsideration Rules are in force. The finalized Boiler MACT rule was announced in December 2012, after the modeling work for *AEO2013* was completed. The provisions of the finalized Boiler MACT rule are less stringent than the provisions of the Final Rule and the partial Reconsideration Rule assumed in the Reference case. For *AEO2013*, the upgrade costs of Boiler MACT were implemented in the Macroeconomic Activity Module (MAM). Upgrade costs used are the "nonproductive costs," which are not associated with efficiency improvements. The upgrade costs are applied as an aggregated cost across all industries. Because of this aggregation of cost and the need for consistency across industries, the cost in the MAM is manifested as a reduction in shipments in the Industrial Demand Module. There is little difference in the cost of compliance for major sources between the March 2011 Final Rule and the December 2011 Reconsideration Rule, and there is no difference for area sources.

Boiler MACT has two compliance groups with different obligations: major source [*32*] and area source. A site that contains one or more boilers or process heaters that have the potential to emit 10 or more tons of any one HAP per year, or 25 tons or more of a combination of HAP per year, is a major source [*33*]. An emissions site that is not a major source is classified as an area source [*34*]. The characteristics of the site determine the compliance group of the boiler. Generally, compliance measures include regular maintenance and tuneups for smaller facilities and emission limits and performance tests for larger facilities. In the Reconsideration Rule, EIA calculations based on EPA estimates revealed that there were 14,111 existing major source boilers in 2011 [*35*]. Of those, calculations based on EPA estimates revealed that 16 percent burn fuels that potentially may subject them to specific emissions limits and annual performance tests. The existing number of affected area source boilers in 2011 was estimated at 189,450 by EIA, using data from EPA [*36*].

To comply with Boiler MACT, major source boilers and process heaters whose heat input is less than 10 million Btu per hour must receive tuneups every 2 years [*37*]. Most existing and new major source boilers or process heaters with heat inputs 10 million Btu per hour or greater that burn coal, biomass, liquid, or "other" gas are subject to emission limits on all five of the HAP listed above [*38*]. Larger major source boilers with heat input of 25 million Btu per hour or greater that burn coal, biomass, or residual oil must use a continuous emission monitoring system for PM [*39*]. Major source boilers with heat inputs of 10 million Btu per hour or more that burn natural gas or refinery gas, as well as metal process furnaces, are not subject to specific emissions limits or performance tests [*40*]. Existing major source boilers must comply with the Final Rule by March 21, 2014; new major source boilers must comply by May 20, 2011, or upon startup, whichever is later [*41*].

Area source natural gas-fired boilers are not subject to Boiler MACT. Area source coal-fired boilers whose heat input is less than 10 million Btu per hour and biomass-fired and liquid fuel-fired boilers of any size must receive a tuneup every 2 years. Existing area source boilers with heat input of 10 million Btu per hour or greater are subject to emissions limits, must receive an initial energy assessment, and must undergo performance tests every 3 years [*42*]. Existing and new coal-fired boilers must meet Hg and CO limits; new coal-fired boilers must also meet limits for PM. New oil-fired and biomass-fired boilers must meet emissions limits only for PM [*43*]. Existing area source boilers subject to an energy assessment and emissions limits must comply by March 21, 2014.

5. State renewable energy requirements and goals: Update through 2012

To the extent possible, *AEO2013* incorporates the impacts of state laws requiring the addition of renewable generation or capacity by utilities doing business in the states. Currently, 30 states and the District of Columbia have an enforceable renewable portfolio standard (RPS) or similar law (Table 3). Under such standards, each state determines its own levels of renewable generation, eligible technologies [*44*], and noncompliance penalties. *AEO2013* includes the impacts of all RPS laws in effect at the end of 2012 (with the exception of Alaska and Hawaii, because NEMS provides electricity market projections for the contiguous lower 48 states only). However, the projections do not include policies with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources. In addition, NEMS does not treat fuel-specific provisions—such as those for solar and offshore wind energy—as distinct targets. Where applicable, such distinct targets (sometimes referred to as "tiers," "set-asides," or "carve-outs") may be subsumed into the broader targets, or they may not be included in the modeling because they could be met with existing capacity and/or projected growth based on modeled economic and policy factors.

In the *AEO2013* Reference case, states generally are projected to meet their ultimate RPS targets. The RPS compliance constraints in most regions are approximated, because NEMS is not a state-level model, and each state generally represents only a portion of one of the NEMS electricity regions. Compliance costs in each region are tracked, and the projection for total renewable generation is checked for consistency with any state-level cost-control provisions, such as caps on renewable credit prices, limits on state compliance funding, or impacts on consumer electricity prices. In general, EIA has confirmed the states' requirements through original documentation, although the Database of State Incentives for Renewables & Efficiency was also used to support those efforts [*45*].

No new RPS programs were enacted over the past year; however, some states with existing RPS programs made modifications in 2012, as discussed below. The aggregate RPS requirement for the various state programs, as modeled in *AEO2013*, is shown in Figure 12. In 2025 the targets account for about 10 percent of U.S. electricity sales. The requirement is derived from the legal targets and projected sales and does not account for any of the discretionary or nondiscretionary waivers or limits on compliance found in most state RPS programs.

At present, most states are meeting or exceeding their required levels of renewable generation based on qualified generation [*46*]. A number of factors have helped to create an environment favorable for RPS compliance, including a surge of new RPS-qualified generation capacity timed to take advantage of federal incentives that either have expired or were scheduled to expire; significant reductions in the cost of renewable technologies like wind and solar; and generally reduced growth (or, in some cases, even contraction) of electricity sales. In addition to the availability of federal tax credits, which historically have gone through a cycle of expiration and renewal, renewable energy projects were given access to other options for federal support, including cash grants (also known as Section 1603 grants) and loan guarantees. The short-term availability of federal incentives has helped to make renewable capacity attractive to investors and helped utilities meet state requirements or potential future load growth in advance (that is, build ahead of time to take advantage of the federal incentives). The attractiveness of renewable projects to investors has also been supported by declining equipment costs for wind turbines and solar photovoltaic systems, as well as by improvements in the performance of those technologies. The declines in technology cost are, in themselves, the result of a complex set of interactions of policy, market, and engineering factors. Finally, most state RPS programs have targets that are tied to retail electricity sales; and with relatively slow growth in electricity sales in most parts of the country, the renewable generation that has entered service recently has gone further toward meeting the proportionally lower targets for absolute amounts of energy (that is, for kilowatthours of energy, as opposed to energy as a percent of sales).

Figure 12. Total renewable generation required for combined state renewable portfolio standards and projected total achieved, 2012-2040 (billion kilowatthours)

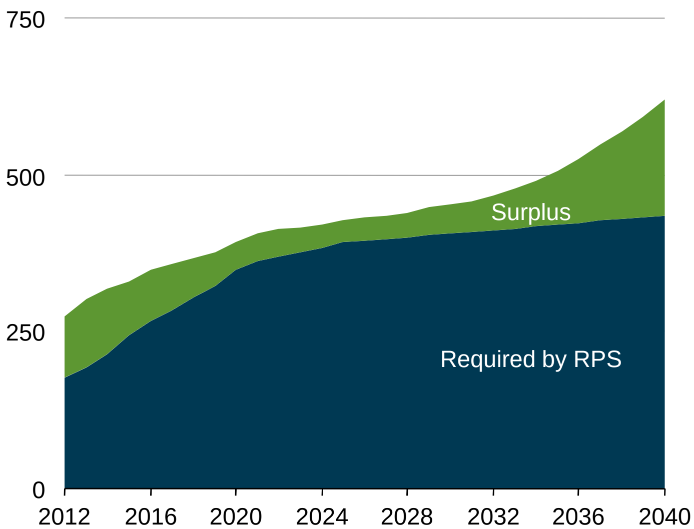


Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
AZ	15% by 2025	Solar, wind, biomass, hydropower, landfill gas (LFG), anaerobic digestion built after January 1, 1997	Direct use of solar heat, ground-source heat pumps, and renewable-fueled combined heat and power (CHP), cogeneration, and fuel cells	Credit trading is allowed, with some bundling restrictions. Includes distributed generation requirement, starting at 5% of target in 2007, growing to 30% in 2012 and beyond.
CA	33% by 2020	Solar, wind, biomass, geothermal, LFG and municipal solid waste (MSW), small hydro, biodiesel, anaerobic digestion, and marine	Energy storage	Credit trading is allowed, with some restrictions. Renewable energy credit prices are capped at $50 per megawatthour.
CO	30% by 2020 for investor-owned utilities; 33% by 2025 for electric cooperatives and municipal utilities serving more than 40,000 customers	Solar, wind, biomass, hydro, biomass, geothermal electric, and anaerobic digestion	Recycled energy	Credit trading is allowed. The distributed renewables requirement (30% of target) applies to investor-owned utilities. Generation from in-state and solar projects is eligible to earn credit multipliers, as is generation associated with certain projects that have specific ownership or transmission ties with small utilities, entities, or individuals.
CT	27% by 2020 (23% renewables, 4% efficiency and CHP)	Solar, wind, hydro (with exceptions), LFG/MSW, anaerobic energy, marine	CHP/cogeneration	Credit trading is allowed. Obligated providers may comply via an alternative compliance payment of $55 per megawatthour. The target is made up of four source tiers with tier-specific targets.
DE	25% by 2026	Solar, wind, biomass, hydro, geothermal, LFG, anaerobic digestion, marine	Fuel cells, distributed generation	Credit trading is allowed. Credit multipliers are awarded for several compliance specifications, including generation from in-state distributed solar and renewable-fueled fuel cells and offshore wind. Target increases for some suppliers can be subject to a cost threshold.
DC	20% by 2020	Solar, wind, biomass, hydro, geothermal, LFG/MSW, marine	Cofiring	Credit trading is allowed. Target includes a solar-specific set-aside, equivalent to 2.5% of sales by 2023. Obligated providers may also comply via a tier-specific alternative compliance payment.
HI	40% by 2030	Solar, wind, biomass, hydro, geothermal, LFG/MSW, anaerobic digestion, marine, certain biofuels	Direct use of solar, ground-source heat pumps, ice storage, CHP/cogeneration, efficiency programs, fuel cells using renewable fuels, hydrogen	Credits cannot be traded. Eligibility of several of the "qualifying other" displacement technologies is restricted after 2015. Utility companies can calculate compliance over all utility affiliates.
IL	25% by 2026	Solar, wind, biomass, hydro, anaerobic digestion, biodiesel	None	Credit trading is allowed. Target includes specific requirements for wind, solar, and distributed generation. The procurement process is subject to a cost cap.
IA	105 megawatts of eligible renewable resources	Wind, solar, some types of biomass and waste, small hydropower	None	Iowa's investor-owned utilities currently are in full compliance with this standard, achieved primarily through wind capacity.

(continued on next page)

Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates (continued)

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
KS	20% of each demand capacity by 2020	Solar, wind, hydro, biomass, LFG, renewable-fueled fuel cells	Direct use of solar heat	Credit trading is allowed. Eligible in-state capacity counts for 1.1 times its actual capacity.
ME	40% total by 2017, 10% by 2017 from new resources entering service in 2005 and beyond	Solar, LFG, wind, biomass, hydro, geothermal, MSW, marine	Fuel cells, CHP/ cogeneration	Credit trading is allowed. The Maine Public Utilities Commission sets an annually adjusted alternative compliance payment. Community-based generation projects are eligible to earn credit multipliers.
MD	20% by 2022	Solar, wind, biomass, geothermal, LFG/ MSW, anaerobic digestion, marine	Solar water heat, ground-source heat pumps	Credit trading allowed. The target includes a solar specific set-aside. Utilities may pay an alternative compliance payment in lieu of procuring eligible sources, with a tier-specific compliance schedule.
MA	22.1% by 2020 (and an additional 1% per year thereafter)	Solar, wind, hydro, some biomass technologies, LFG/MSW, geothermal electric, anaerobic digestion, marine, renewable-fueled fuel cells	None	Credit trading is allowed. The target for new resources includes a solar-specific goal to achieve 400 megawatts of in-state solar capacity, which is translated into an annual target for obligated providers. Obligated providers may comply via an alternative compliance payment (ACP), which varies in level by the requirement class, although the ACP is designed to be higher than the cost of other compliance options.
MI	10% by 2015, with specific new capacity goals for utilities that serve more than 1 million customers	Solar, wind, hydro, biomass, LFG/MSW, geothermal electric, anaerobic digestion, marine	CHP/cogeneration, coal with carbon capture and sequestration, and energy efficiency measures for up to 10 percent of a utility's sales obligation	Credit trading is allowed. Solar power receives a credit multiplier, while other generation and equipment features—such as peak generation, storage, and use of equipment manufactured in-state—can earn fractional bonus credits.
MN	30% by 2020 (Xcel Energy) or 25% by 2025 (other utilities)	Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion	Hydrogen (generated from renewable sources), cofiring	Credit trading is allowed. Xcel's target must achieve 25 percent of sales specifically from wind and solar (with a 1-percent maximum for solar). State regulators can penalize noncompliance at the estimated cost of compliance.
MO	15% by 2021	Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion, ethanol, renewable-fueled fuel cells	None	Credit trading is allowed. Non-compliance payments are set at double the market rate for renewable energy credits. Solar must account for 20% of the annual target.
MT	15% by 2015	Solar, wind, hydro, geothermal, biomass, LFG	Compressed air storage	Credit trading is allowed, with a price cap of $10 per megawatthour. There are specific targets for community-based projects.
NV	25% by 2025	Solar, wind, hydro, geothermal, biomass, LFG/MSW	Waste tires, direct use of solar and geothermal heat, efficiency measures (which can account for one-quarter of the target in any given year)	Credit trading is allowed. Photovoltaics receives a credit premium, with an additional premium for customer-sited systems.
NH	24.8% by 2025	Solar, wind, small hydro, marine, LFG	Fuel cells, CHP, microturbines, direct use of solar heat, ground-source heat pumps	Credit trading is allowed, and utilities may pay into a fund in lieu of holding credits. The target comprises four separate compliance classes, broken out by technology.

(continued on next page)

Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates (continued)

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
NJ	20.38% by 2021, with an additional 4.1% solar by 2027	Solar, wind, hydro, geothermal, LFG/MSW, marine	None	Credit trading is allowed, with an alternative compliance payment set by state regulators. Solar and offshore wind are subject to separate requirements and have separate enforcement provisions.
NM	20% by 2020 for investor-owned utilities, 10% by 2020 for cooperatives	Solar, wind, hydro, geothermal, LFG	Zero-emission technology, not including nuclear	Credit trading is allowed. The program cannot increase consumer costs beyond a threshold amount, increasing to 3 percent of annual costs by 2015. Technology minimums are established for wind, solar, and certain other resources.
NY	29% by 2015	Solar, wind, hydro, geothermal, biomass, LFG, marine	Direct use of solar heat, fuel cells	Credit trading is not allowed. Compliance is achieved through purchases by state authorities, funded by a surcharge on investor-owned utilities. Government-owned utilities may have their own, similar programs.
NC	12.5% by 2021 for investor-owned utilities; 10% by 2018 for municipal and cooperative utilities	Solar, wind, small hydro, biomass, geothermal, LFG, marine	Direct use of solar heat, CHP, hydrogen, demand reduction	Credit trading is allowed. Impacts on customer costs are capped at specified levels. There are specific targets for solar and certain animal waste projects.
OH	12.5% by 2024	Solar, wind, hydro, biomass, geothermal, LFG/MSW	Energy storage, separate 12.5% target for “advanced energy technologies,” including coal mine methane, advanced nuclear, and efficiency	Credit trading is allowed. Alternative compliance payments are set by law and adjusted annually. There is a separate target for solar energy.
OR	5% by 2025 for utilities with less than 1.5% of total sales; 10% by 2025 for utilities with less than 3% of total sales; 25% by 2025 for all others	Solar, wind, hydro, biomass, geothermal, LFG/MSW, marine	Hydrogen	Credit trading is allowed, with an alternative compliance payment and a limit on expenditures of 4% of annual revenue. Solar receives a credit multiplier.
PA	18% by 2020	Solar, wind, hydro, biomass, LFG/MSW	Certain advanced coal technologies, certain energy efficiency technologies, fuel cells, direct use of solar heat, ground-source heat pumps	Credit trading is allowed, with an alternative compliance payment. There are separate targets for solar and two different combinations of renewable, fossil, and efficiency technologies.
RI	16% by 2019	Solar, wind, hydro, biomass, geothermal, LFG, marine	None	Credit trading is allowed, with an alternative compliance payment. There is a separate target for 90 megawatts of new renewable capacity.
TX	5,880 megawatts by 2018	Solar, wind, hydro, biomass, geothermal, LFG, marine	Direct use of solar heat, ground-source heat pumps	Credit trading is allowed, with capacity targets converted to generation equivalents. State regulators may cap credit prices. 500 megawatts must be from resources other than wind.
WA	15% by 2020	Solar, wind, hydro, biomass, geothermal, LFG, marine	Combined heat and power	Credit trading is allowed, with an administrative penalty for noncompliance.
WV	25% by 2025	Solar, wind, hydro, biomass, geothermal, small hydro	Several coal and natural gas generation sources	Credit trading is allowed, with noncompliance assessments to be determined by state regulators. Renewable generation may receive credit multipliers, with additional credit earned for locating on abandoned strip mines.

Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates (continued)

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
WI	10% by 2015	Solar, wind, hydro, biomass, geothermal, LFG/MSW, small hydro, marine	Pyrolysis [*47*], synthetic gas, direct use of solar or biomass heat, ground-source heat pumps	Credit trading is allowed.

EIA projects that, overall, RPS-qualified generation will continue to meet or exceed aggregate targets for state RPS programs through 2040, as shown in Figure 12. Through the next decade, the surplus qualifying generation will decline gradually, as little additional qualifying capacity is added, allowing the targets to catch up with supply. By the end of the projection horizon, however, the surplus widens substantially as renewable generation technologies become increasingly competitive with conventional generation sources. It should be noted that the aggregate targets and qualifying generation shown in Figure 12 may mask significant regional variation, with some regions producing excess qualifying generation and others producing just enough to meet the requirement or even needing to import generation from adjoining regions to meet state targets. Furthermore, just because there is, in aggregate, more qualifying generation than is needed to meet the targets, this does not necessarily imply that projected generation would be the same without state RPS policies. State RPS policies may encourage investment in places where it otherwise would not occur, or would not occur in the amounts projected, even as other parts of the country see substantial growth above state targets, or even in their absence. It does, however, suggest that state RPS programs will not be the sole reason for future growth in renewable generation.

Recent RPS modifications

A number of states modified their RPS programs in 2012, either through regulatory proceedings or through legislative action. These changes are reflected in Table 3. The changes affect some aspects of the laws and implementing regulations, but they do not have substantive effects on the representation of the RPS programs in *AEO2013*. Key changes include:

California

California Assembly Bill 2196, which establishes requirements for certain biomass-based generation resources, requires that biomass-derived gas be produced on site or sourced from a common carrier pipeline that operates within the state. It also sets additional requirements related to the in-service date of a common carrier source and the ability to claim certain environmental benefits from the use of such sources.

Maryland

The state enacted a series of bills that accelerate the solar-specific compliance schedule (while leaving the aggregate RPS target unchanged) and expand the tier 1 requirement category to include thermal output from certain animal waste and ground-source heat pumps.

Massachusetts

The Department of Energy Resources issued final rules regarding the use of certain biomass resources to meet the RPS standard. Biomass facilities must meet certain conditions with regard to conversion technology and feedstock sourcing to be eligible for use in meeting the standard.

New Hampshire

Senate Bill 218 allows certain thermal resources, including heat derived from qualified solar, geothermal, and biomass sources, to meet renewable energy targets. It also allows electricity produced from the cofiring of biomass in certain existing coal plants to meet the requirements. The bill also adjusts the total renewable energy target upward by 1 percentage point, to 24.8 percent by 2025.

New Jersey

Senate Bill 1925 changed the compliance schedule for the solar component of the RPS. The revised law is implemented with a solar target of 3.47 percent of sales by 2021.

Ohio

The legislature passed a set of laws that allow certain types of cogeneration facilities to qualify in meeting the RPS.

6. California Assembly Bill 32: Emissions cap-and-trade as part of the Global Warming Solutions Act of 2006

California's AB 32, the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set California's overall GHG emissions reduction goal to its 1990 level by 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California, including a cap-and-trade program [*48*]. In addition to the cap-and-trade program, other authorized measures include the LCFS; energy efficiency goals and programs in transportation, buildings, and industry; combined heat and power goals; and RPS [*49*].

The cap-and-trade program features an enforceable cap on GHG emissions that will decline over time. CARB will distribute tradable allowances equal to the emissions allowed under the cap. Enforceable compliance obligations begin in 2013 for the electric power sector, including electricity imports, and for industrial facilities. Fuel providers must comply starting in 2015. All facilities that emit 25,000 metric tons carbon dioxide equivalent (CO_2e) or more are subject to cap-and-trade regulations. The only exception is that, starting in 2015, all importers of electricity from electric facilities outside of California will be subject to cap-and-trade regulations, even from facilities that emit less than 25,000 metric tons CO_2e [*50*].

The most significant GHG covered under the program is CO_2, but the cap-and-trade program covers several other GHGs [*51*], including methane, nitrous oxide, perfluorocarbons, chlorofluorocarbons, nitrogen trifluoride, and sulfur hexafluoride [*52*]. In 2007, CARB determined that 427 million metric tons carbon dioxide equivalent (MMTCO_2e) was the total state-wide GHG emissions level in 1990 and, therefore, would be the 2020 emissions goal. CARB estimates that the implementation of the cap-and-trade program will reduce GHG emissions by between 18 and 27 MMTCO_2e in 2020 [*53*].

The enforceable cap goes into effect in 2013, and there are three multi-year compliance periods:

- Compliance period 1 (2013-2014) includes sources of GHG emissions responsible for more than one-third of state-wide emissions.
- Compliance period 2 (2015-2017) covers sources of GHG emissions responsible for about 85 percent of state-wide emissions.
- Compliance period 3 (2018-2020) covers the same sources as Compliance Period 2 [*54*].

The electric power and industrial sectors are required to comply with the cap starting in 2013. Providers of natural gas, propane, and transportation fuels are required to comply starting in 2015, when the second compliance period begins. For the first compliance period, covered entities are required to submit allowances for up to 30 percent of their annual emissions in each year; however, at the end of 2014 they are required to account for all the emissions for which they were responsible during the 2-year period. Each covered entity can also use offsets to meet up to 8 percent of its compliance obligation. Offsets used as part of the program must be approved by CARB and can be canceled later by CARB for certain reasons (a provision known as "buyer liability").

A majority (51 percent) of the allowances [*55*] allocated over the initial 8 years of the program will be distributed through price containment reserves and auctions, which will be held quarterly when the program commences. CARB's first allowance auction was held in November 2012 [*56*]. Future auctions may be linked to Québec's cap-and-trade program [*57*]. Twenty-five percent of the allowances are allocated directly to electric utilities that sell electricity to consumers in the state. Seventeen percent of the allowances are allocated directly to affected industrial facilities in order to mitigate the economic impact of the cap on the industrial sector [*58*]. Allowance allocations for the industrial sector are based on output. Starting in 2013, the number of allowances allocated annually to the industrial sector declines linearly to 50 percent of the original total in 2020. The remaining 7 percent of the allowances issued in a given year go into a price containment reserve, to be used only if allowance prices rise above a set amount in quarterly auctions.

The AB 32 cap-and-trade provisions, which were incorporated only for the electric power sector in *AEO2012*, are more fully implemented in *AEO2013*, adding industrial facilities, refineries, fuel providers, and non-CO_2 GHG emissions. The allowance price, representing the incremental cost of complying with AB 32 cap-and-trade, is modeled in the NEMS Electricity Market Module via a region-specific emissions constraint. This allowance price, when added to the market fuel prices, results in higher effective fuel prices [*59*] in the demand sectors. Limited banking and borrowing, as well as a price containment reserve [*60*] and offsets, also have been modeled, providing some compliance flexibility and cost containment. NEMS macroeconomic effects are based on an energy-economy equilibrium that reacts to changes in energy prices and energy consumption; however, no macroeconomic effects are assumed explicitly from the AB 32 cap-and-trade provisions.

7. California low carbon fuel standard

The LCFS, administered by CARB [*61*], is designed to reduce by 10 percent the average carbon intensity of motor gasoline and diesel fuels sold in California from 2012 to 2020 through the increased sale of alternative "low-carbon" fuels. Regulated parties generally are the fuel producers and importers who sell motor gasoline or diesel fuel in California. The program is assumed to remain in place at 2020 levels from 2021 to 2040 in *AEO2013.* The carbon intensity of each alternative low-carbon fuel, based on life-cycle analyses conducted under the guidance of CARB for a number of approved fuel pathways, is calculated on an energy-equivalent basis, measured in grams of CO_2-equivalent emissions per megajoule.

AEO2013 incorporates the LCFS by requiring that the average carbon intensity of motor fuels sold for use in California meets the carbon intensity targets. For the *AEO2013* Reference case, carbon intensity targets and the carbon intensities of alternative fuels were adapted from the "Third Notice of Public Availability of Modified Text and Availability of Additional Documents and

Information" [*62*]. Key uncertainties in the modeling of the LCFS are the availability of low-carbon fuels in California and what actions CARB may take if the LCFS is not met. In *AEO2013*, these uncertainties are addressed by assuming that fuel providers can purchase low-carbon credits if low-carbon fuels cannot be produced and sold at reasonable prices.

In December 2011, the U.S. District Court for the Eastern Division of California ruled in favor of several trade groups that claimed the LCFS violated the interstate commerce clause of the U.S. Constitution by seeking to regulate farming and ethanol production practices in other states. The court granted an injunction blocking enforcement of the LCFS by CARB [*63*]. In April 2012, the U.S. Ninth District Court of Appeals granted a stay of injunction while CARB appeals the original ruling [*64*]. Although the future of the LCFS program remains uncertain, the stay of the injunction requires that the program be enforced.

Endnotes for Legislation and regulations

Links current as of March 2013

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Issues in focus

Introduction

The "Issues in focus" section of the *Annual Energy Outlook (AEO)* provides an in-depth discussion on topics of special significance, including changes in assumptions and recent developments in technologies for energy production and consumption. Selected quantitative results are available in Appendix D. The first topic updates a discussion included in a number of previous *AEO*s that compared the Reference case to the results of two cases with different assumptions about the future course of existing energy policies. One case assumes the elimination of sunset provisions in existing energy policies; that is, the policies are assumed not to terminate as they would under current law. The other case assumes the extension or expansion of a selected group of existing policies—corporate average fuel economy (CAFE) standards, appliance standards, and production tax credits (PTCs)—in addition to the elimination of sunset provisions.

Other topics discussed in this section, as identified by numbered subsections below, include (2) oil price and production trends in *Annual Energy Outlook 2013 (AEO2013)*; (3) petroleum import dependence under a range of cases; (4) competition between coal and natural gas in the electric power sector; (5) nuclear power in *AEO2013*; and (6) the impact of natural gas liquids (NGL) growth.

The topics explored in this section represent current and emerging issues in energy markets. However, many of the topics discussed in previous *AEO*s also remain relevant today. Table 4 provides a list of titles from the 2012, 2011, and 2010 *AEO*s that are likely to be of interest to today's readers—excluding topics that are updated in *AEO2013*. The articles listed in Table 4 can be found on the U.S. Energy Information Administration (EIA) website at http://www.eia.gov/analysis/reports.cfm?t=128.

1. No Sunset and Extended Policies cases

Background

The *AEO2013* Reference case is best described as a current laws and regulations case because it generally assumes that existing laws and regulations remain unchanged throughout the projection period, unless the legislation establishing them sets a sunset date or specifies how they will change. The Reference case often serves as a starting point for analysis of proposed changes in legislation or regulations. While the definition of the Reference case is relatively straightforward, there may be considerable interest in a variety of alternative cases that reflect updates or extensions of current laws and regulations. Areas of particular interest include:

- Laws or regulations that have a history of being extended beyond their legislated sunset dates. Examples include the various tax credits for renewable fuels and technologies, which have been extended with or without modifications several times since their initial implementation.

Table 4. Key analyses from "Issues in focus" in recent *AEO*s

AEO2012	*AEO2011*	*AEO2010*
Potential efficiency improvements and their impacts on end-use energy demand	Increasing light-duty vehicle greenhouse gas and fuel economy standards for model years 2017 to 2025	Energy intensity trends in *AEO2010*
Energy impacts of proposed CAFE standards for light-duty vehicles, model years 2017 to 2025	Fuel consumption and greenhouse gas emissions standards for heavy-duty vehicles	Natural gas as a fuel for heavy trucks: issues and incentives
Impacts of a breakthrough in battery vehicle technology	Potential efficiency improvements in alternative cases for appliance standards and building codes	Factors affecting the relationship between crude oil and natural gas prices
Heavy-duty natural gas vehicles	Potential of offshore crude oil and natural gas resources	Importance of low permeability natural gas reservoirs
Changing structure of the refining industry	Prospects for shale gas	U.S. nuclear power plants: continued life or replacement after 60?
Changing environment for fuel use in electricity generation	Cost uncertainties for new electric power plants	Accounting for carbon dioxide emissions from biomass energy combustion
Nuclear power in *AEO2012*	Carbon capture and storage: economics and issues	
Potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production	Power sector environmental regulations on the horizon	
U.S. crude oil and natural gas resource uncertainty		
Evolving Marcellus Shale gas resource estimates		

- Laws or regulations that call for periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. Department of Energy (DOE) and CAFE and greenhouse gas (GHG) emissions standards for vehicles issued by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA).
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act that require EPA to issue or revise regulations if it finds that an environmental quality target is not being met.

Two alternative cases are discussed in this section to provide some insight into the sensitivity of results to scenarios in which existing tax credits or other policies do not sunset. No attempt is made to cover the full range of possible uncertainties in these areas, and readers should not view the cases discussed as EIA projections of how laws or regulations might or should be changed. The cases examined here look only at federal laws or regulations and do not examine state laws or regulations.

Analysis cases

The two cases prepared—the No Sunset case and the Extended Policies case—incorporate all the assumptions from the *AEO2013* Reference case, except as identified below. Changes from the Reference case assumptions include the following.

No Sunset case

Tax credits for renewable energy sources in the utility, industrial, and buildings sectors, or for energy-efficient equipment in the buildings sector, are assumed to be extended, including the following:

- The PTC of 2.2 cents per kilowatthour and the 30-percent investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources, assumed in the Reference case to expire at the end of 2012 for wind and 2013 for the other eligible resources, are extended indefinitely. On January 1, 2013, Congress passed a one-year extension of the PTC for wind and modified the qualification rules for all eligible technologies; these changes are not included in the *AEO2013* Reference case, which was completed in December 2012, but they are discussed in a box on page 22.
- For solar power investments, a 30-percent ITC that is scheduled to revert to a 10-percent credit in 2016 is, instead, assumed to be extended indefinitely at 30 percent.
- In the buildings sector, personal tax credits for the purchase of renewable equipment, including photovoltaics (PV), are assumed to be extended indefinitely, as opposed to ending in 2016 as prescribed by current law. The business ITCs for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016; and the business ITC for solar systems is assumed to remain at 30 percent instead of reverting to 10 percent. On January 1, 2013, legislation was enacted to reinstate tax credits for energy-efficient homes and selected residential appliances. The tax credits that had expired on December 31, 2011, are now extended through December 31, 2013. This change is not included in the Reference case.
- In the industrial sector, the 10-percent ITC for combined heat and power (CHP) that ends in 2016 in the *AEO2013* Reference case [65] is assumed to be preserved through 2040, the end of the projection period.

Extended Policies case

The Extended Policies case includes additional updates to federal equipment efficiency standards that were not considered in the Reference case or No Sunset case. Residential and commercial end-use technologies eligible for incentives in the No Sunset case are not subject to new standards. Other than those exceptions, the Extended Policies case adopts the same assumptions as the No Sunset case, plus the following:

- Federal equipment efficiency standards are assumed to be updated at periodic intervals, consistent with the provisions in existing law, at levels based on ENERGY STAR specifications or on the Federal Energy Management Program purchasing guidelines for federal agencies, as applicable. Standards are also introduced for products that currently are not subject to federal efficiency standards.
- Updated federal energy codes for residential and commercial buildings increase by 30 percent in 2020 compared to the 2006 International Energy Conservation Code in the residential sector and the American Society of Heating, Refrigerating and Air-Conditioning Engineers Building Energy Code 90.1-2004 in the commercial sector. Two subsequent rounds in 2023 and 2026 each add an assumed 5-percent incremental improvement to building energy codes. The equipment standards and building codes assumed for the Extended Policies case are meant to illustrate the potential effects of those policies on energy consumption for buildings. No cost-benefit analysis or evaluation of impacts on consumer welfare was completed in developing the assumptions. Likewise, no technical feasibility analysis was conducted, although standards were not allowed to exceed the “maximum technologically feasible” levels described in DOE’s technical support documents.
- The *AEO2013* Reference, No Sunset, and Extended Policies cases include both the attribute-based CAFE standards for light-duty vehicles (LDVs) in model year (MY) 2011 and the joint attribute-based CAFE and vehicle GHG emissions standards for MY 2012 to MY 2025. The Reference and No Sunset cases assume that the CAFE standards are then held constant at MY 2025 levels in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time. The

Extended Policies case modifies the assumption in the Reference and No Sunset cases, assuming continued increases in CAFE standards after MY 2025. CAFE standards for new LDVs are assumed to increase by an annual average rate of 1.4 percent.

- In the industrial sector, the ITC for CHP is extended to cover all properties with CHP, no matter what the system size (instead of being limited to properties with systems smaller than 50 megawatts as in the Reference case [66]), which may include multiple units. Also, the ITC is modified to increase the eligible CHP unit cap to 25 megawatts from 15 megawatts. These extensions are consistent with previously proposed legislation.

Analysis results

The changes made to the Reference case assumptions in the No Sunset and Extended Policies cases generally lead to lower estimates for overall energy consumption, increased use of renewable fuels particularly for electricity generation and reduced energy-related carbon dioxide (CO_2) emissions. Because the Extended Policies case includes most of the assumptions in the No Sunset case but adds others, the effects of the Extended Policies case tend to be greater than those in the No Sunset case—but not in all cases, as discussed below. Although these cases show lower energy prices, because the tax credits and end-use efficiency standards lead to lower energy demand and reduce the costs of renewable technologies, appliance purchase costs are also affected. In addition, the government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Energy consumption

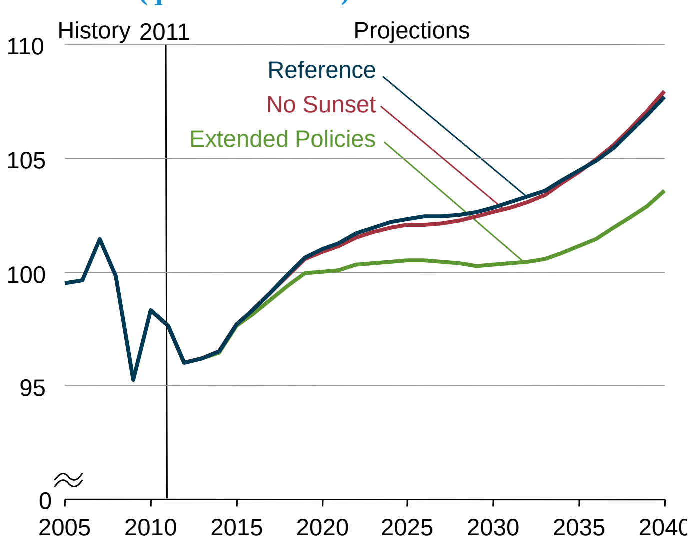
Total energy consumption in the No Sunset case is close to the level in the Reference case (Figure 13). Improvements in energy efficiency lead to reduced consumption in this case, but somewhat lower energy prices lead to relatively higher levels of consumption, partially offsetting the impact of improved efficiency. In 2040, total energy consumption in the Extended Policies case is 3.8 percent below the Reference case projection.

Buildings energy consumption

Renewable distributed generation (DG) technologies (PV systems and small wind turbines) provide much of the buildings-related energy savings in the No Sunset case. Extended tax credits in the No Sunset case spur increased adoption of renewable DG, leading to 61 billion kilowatthours of onsite electricity generation from DG systems in 2025, compared with 28 billion kilowatthours in the Reference case. Continued availability of the tax credits results in 137 billion kilowatthours of onsite electricity generation in 2040 in the No Sunset case—more than three times the amount of onsite electricity generated in 2040 in the Reference case. Similar adoption of renewable DG occurs in the Extended Policies case. With the additional efficiency gains from assumed future standards and more stringent building codes, delivered energy consumption for buildings is 3.9 percent (0.8 quadrillion British thermal units [Btu]) lower in 2025 and 8.0 percent (1.7 quadrillion Btu) lower in 2040 in the Extended Policies case than in the Reference case. The reduction in 2040 is more than seven times as large as the 1.1-percent (0.2 quadrillion Btu) reduction in the No Sunset case.

Electricity use shows the largest reduction in the two alternative cases compared to the Reference case. Building electricity consumption is 1.3 percent and 5.8 percent lower, respectively, in the No Sunset and Extended Policies cases in 2025 and 2.1 percent and 8.7 percent lower, respectively, in 2040 than in the Reference case, as onsite generation continues to increase and updated standards affect a greater share of the equipment stock in the Extended Policies case. Space heating and cooling are affected by the assumed standards and building codes, leading to significant savings in energy consumption for heating and cooling in the Extended Policies case. In 2040, delivered energy use for space heating in buildings is 9.6 percent lower, and energy use for space cooling is 20.3 percent lower, in the Extended Policies case than in the Reference case. In addition to improved standards and codes, extended tax credits for PV prompt increased adoption, offsetting some of the costs for purchased electricity for cooling. New standards for televisions and for personal computers and related equipment in the Extended Policies case lead to savings of 28.3 percent and 31.8 percent, respectively, in residential electricity use for this equipment in 2040 relative to the Reference case. Residential and commercial natural gas use declines from 8.1 quadrillion Btu in 2011 to 7.8 quadrillion Btu in 2025 and 7.2 quadrillion Btu in 2040 in the Extended Policies case, representing a 2.2-percent reduction in 2025 and a 8.5-percent reduction in 2040 relative to the Reference case.

Figure 13. Total energy consumption in three cases, 2005-2040 (quadrillion Btu)



Industrial energy consumption

The No Sunset case modifies the Reference case assumptions by extending the existing ITC for industrial CHP through 2040. The Extended Policies case starts from the No Sunset case and expands the credit to include industrial CHP systems of all sizes and raises the maximum credit that can be claimed from 15 megawatts of installed capacity to 25 megawatts. The changes result in 1.6 gigawatts of additional industrial CHP capacity in the No Sunset case compared with the Reference case in 2025 and 3.5 gigawatts of additional capacity in 2040. From 2025 through 2040, more CHP capacity is installed in the No Sunset case than in the Extended Policy case. CHP capacity is 0.3 gigawatts higher in the No Sunset Case than in the Extended Policies Case in 2025 and 1.2 gigawatts higher in 2040. Although the Extended Policies case includes a higher tax benefit for CHP than the No Sunset case, which by itself provides greater incentive to build CHP capacity, electricity prices are lower in the Extended Policies case than in the No Sunset case starting around 2020, and the difference increases over time. Lower electricity prices, all else equal, reduce the economic attractiveness of CHP. Also, the median size of industrial CHP units size is 10 megawatts [*67*], and many CHP systems are well within the 50-megawatt total system size, which means that relaxing the size constraint is not as strong an incentive for investment as is allowing the current tax credit for new CHP investments to continue after 2016.

Natural gas consumption averages 9.7 quadrillion Btu per year in the industrial sector from 2011 to 2040 in the No Sunset case—about 0.1 quadrillion Btu, or 0.9 percent, above the level in the Reference case. Over the course of the projection, the difference in natural gas consumption between the No Sunset case and the Reference case is small but increases steadily. In 2025, natural gas consumption in the No Sunset case is approximately 0.1 quadrillion Btu higher than in the Reference Case, and in 2040 it is 0.2 quadrillion Btu higher. Natural gas consumption in the Extended Policies case is virtually the same as in the No Sunset case through 2030. After 2030, refinery use of natural gas stabilizes in the Extended Policies case as continued increases in CAFE standards reduce demand for petroleum products.

Transportation energy consumption

The Extended Policies case differs from the Reference and No Sunset cases in assuming that the CAFE standards recently finalized by EPA and NHTSA for MY 2017 through 2025 (which call for a 4.1-percent annual average increase in fuel economy for new LDVs) are extended through 2040 with an assumed average annual increase of 1.4 percent. Sales of vehicles that do not rely solely on a gasoline internal combustion engines for both motive and accessory power (including those that use diesel, alternative fuels, or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards after 2025, growing to almost 72 percent of new LDV sales in 2040, compared with about 49 percent in the Reference case.

LDV energy consumption declines in the Reference case from 16.1 quadrillion Btu (8.7 million barrels per day) in 2011 to 14.0 quadrillion Btu (7.7 million barrels per day) in 2025 as a result of the increase in CAFE standards. Extension of the increases in CAFE standards in the Extended Policies case further reduces LDV energy consumption to 11.9 quadrillion Btu (6.5 million barrels per day) in 2040, or about 8 percent lower than in the Reference case. Petroleum and other liquid fuels consumption in the transportation sector is virtually identical through 2025 in the Reference and Extended Policies cases but declines in the Extended Policies case from 13.3 million barrels per day in 2025 to 12.3 million barrels per day in 2040, as compared with 13.0 million barrels per day in 2040 in the Reference case (Figure 14).

Renewable electricity generation

The extension of tax credits for renewables through 2040 would, over the long run, lead to more rapid growth in renewable generation than in the Reference case. When the renewable tax credits are extended without extending energy efficiency standards, as assumed in the No Sunset case, there is a significant increase in renewable generation in 2040 compared to the Reference case (Figure 15). Extending both renewable tax credits and energy efficiency standards in the Extended Policies case results in more modest growth

Figure 14. Consumption of petroleum and other liquids for transportation in three cases, 2005-2040 (million barrels per day)

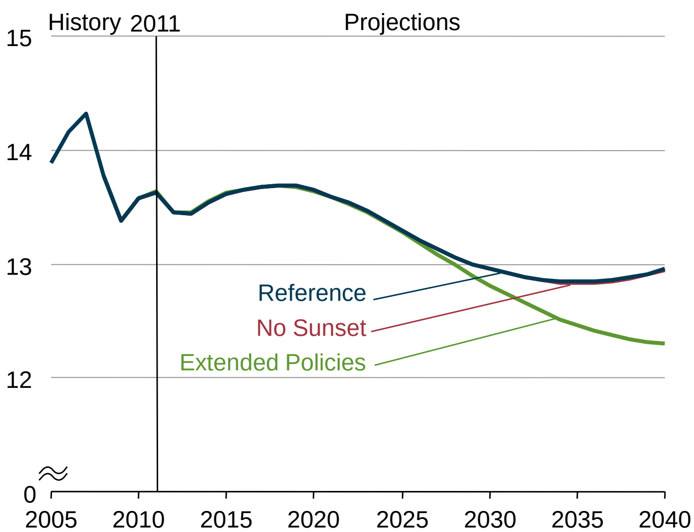
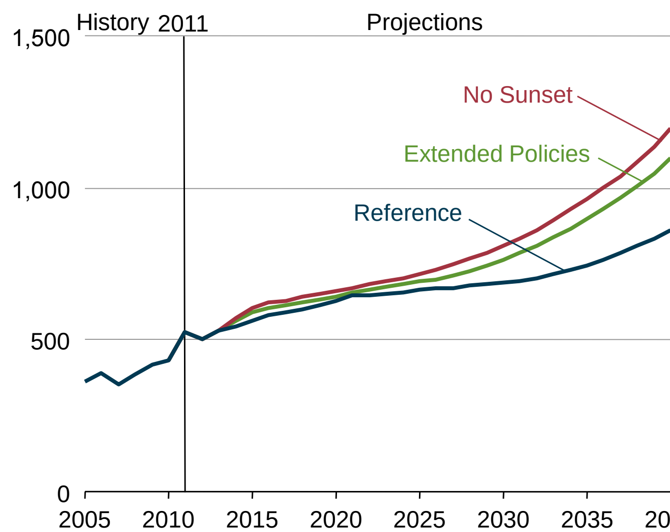


Figure 15. Renewable electricity generation in three cases, 2005-2040 (billion kilowatthours)



in renewable generation, because renewable generation is a significant source of new generation to meet load growth, and enhanced energy efficiency standards tend to reduce overall electricity consumption and the need for new generation resources.

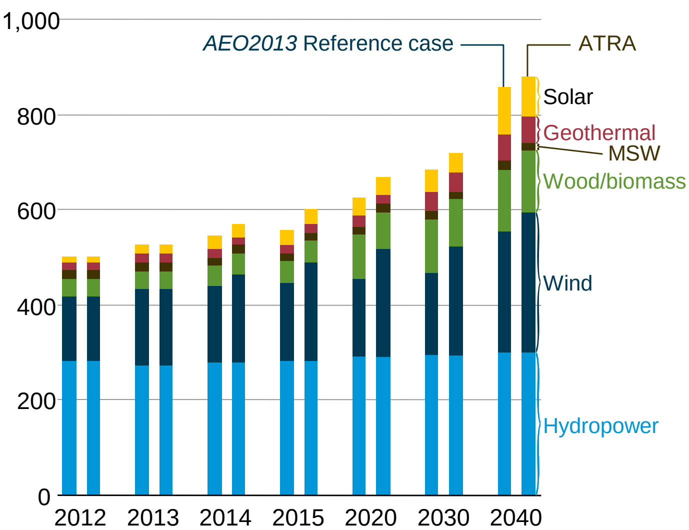
The *AEO2013* Reference case does not reflect the provisions of the American Taxpayer Relief Act of 2012 (P.L. 112-240) passed on January 1, 2013 [*68*], which extends the PTCs for renewable generation beyond what is included in the *AEO2013* Reference case. While this legislation was completed too late for inclusion in the Reference case, EIA did complete an alternative case that examined key energy-related provisions of that legislation, the most important of which is the extension of the PTC for renewable generation. A brief summary of those results is presented in the box, "Effects of energy provisions in the American Taxpayer Relief Act of 2012."

Effects of energy provisions in the American Taxpayer Relief Act of 2012

On January 1, 2013, Congress passed the American Taxpayer Relief Act of 2012 (ATRA). The law, among other things, extended several provisions for tax credits to the energy sector. Although the law was passed too late to be incorporated in the *Annual Energy Outlook 2013 (AEO2013)* Reference case, a special case was prepared to analyze some of its key provisions, including the extension of tax credits for utility-scale renewables, residential energy efficiency improvements, and biofuels [*69*]. The analysis found that the most significant impact on energy markets came from extending the production tax credits (PTCs) for utility-scale wind, and from changing the PTC qualification criteria from being in service on December 31, 2013, to being under construction by December 31, 2013, for all eligible utility-scale technologies. Although there is some uncertainty about what criteria will be used to define "under construction," this analysis assumes that the effective length of the extension is equal to the typical project development time for a qualifying project. For wind, the effective extension is 3 years.

Compared with the *AEO2013* Reference case, ATRA increases renewable generation, primarily from wind (Figure 16). Renewable generation in 2040 is about 2 percent higher in the ATRA case than in the Reference case, with the greatest growth occurring in the near term. In 2016, renewable generation in the ATRA case exceeds that in the Reference case by nearly 9 percent. Almost all the increase comes from wind generation, which in 2016 is about 34 percent higher in the ATRA case than in the Reference case. In 2040, however, wind generation is only 17 percent higher than projected in the Reference case. These results indicate that, while the short-term extension does result in additional wind generation capacity, some builds that otherwise would occur later in the projection period are moved up in time to take advantage of the extended tax credit. The increase in wind generation partially displaces other forms of generation in the Reference case, both renewable and nonrenewable—particularly solar, biomass, coal, and natural gas.

Figure 16. Renewable electricity generation in two cases, 2012-2040 (billion kilowatthours)



ATRA does not have significant effects on electricity or delivered natural gas prices and generally does not result in a difference of more than 1 percent either above or below Reference case prices. In the longer term (beyond 2020), electricity and natural gas prices generally both are slightly lower in the ATRA case, as increased wind capacity reduces variable fuel costs in the power sector and reduces the demand for natural gas.

Other ATRA provisions analyzed had minimal impact on all energy measures, primarily limited to short-term reductions in renewable fuel prices and a one-year window for residential customers to get tax credits for certain efficiency expenditures. Provisions of the act not addressed in this analysis are likely to have only modest impacts because of their limited scale, scope, and timing.

In the No Sunset and Extended Policies cases, renewable generation more than doubles from 2011 to 2040, as compared with a 64-percent increase in the Reference case. In 2040, the share of total electricity generation accounted for by renewables is between 22 and 23 percent in both the No Sunset and Extended Policies cases, as compared with 16 percent in the Reference case.

Construction of wind-generation units slows considerably in the Reference case from recent construction rates, following the assumed expiration of the tax credit for wind power in 2012. The combination of slow growth in electricity demand, little impact from state-level renewable generation requirements, and low prices for competing fuels like natural gas keeps growth relatively low until around 2025, when load growth finally catches up with installed capacity, and natural gas prices increase to a level at which wind is a cost-competitive option in some regions. Extending the PTC for wind spurs a brief surge in near-term development by 2014, but the factors that limit development through 2025 in the Reference case still largely apply, and growth from 2015 to about 2025 is slow, in spite of the availability of tax credits during the 10-year period. When the market picks up again after 2025, availability of the tax credits spurs additional wind development over Reference case levels. Wind generation in the No Sunset case is about 27 percent higher than in the Reference case in 2025 and 86 percent higher in 2040.

In the near term, the continuation of tax credits for solar generation results in a continuation of recent growth trends for this resource. The solar tax credits are assumed to expire in 2016 in the Reference case, after which the growth of solar generation slows significantly. Eventually, economic conditions become favorable for utility-scale solar without the federal tax credits, and the growth rate picks up substantially after 2025. With the extension of the ITC, growth continues throughout the projection period. Solar generation in the No Sunset case in 2040 is more than 30 times the 2011 level and more than twice the level in 2040 in the Reference case.

The impacts of the tax credit extensions on geothermal and biomass generation are mixed. Although the tax credits do apply to both geothermal and biomass resources, the structure of the tax credits, along with other market dynamics, makes wind and solar projects relatively more attractive. Over most of the projection period, geothermal and biomass generation are lower with the tax credits available than in the Reference case. In 2040, generation from both resources in the No Sunset and Extended Policies cases is less than 10 percent below the Reference case levels. However, generation growth lags significantly through 2020 with the tax credit extensions, and generation in 2020 from both resources is about 20 percent lower in the No Sunset and Extended Policy cases than in the Reference case.

After 2025, renewable generation in the No Sunset and Extended Policies cases starts to increase more rapidly than in the Reference case. As a result, generation from nuclear and fossil fuels is below Reference case levels. Natural gas represents the largest source of displaced generation. In 2040, electricity generation from natural gas is 13 percent lower in the No Sunset case and 16 percent lower in the Extended Policies case than in the Reference case (Figure 17).

Energy-related CO_2 emissions

In the No Sunset and Extended Policies cases, lower overall fossil energy use leads to lower levels of energy-related CO_2 emissions than in the Reference case. In the Extended Policies case, the emissions reduction is larger than in the No Sunset case. From 2011 to 2040, energy-related CO_2 emissions are reduced by a cumulative total of 4.6 billion metric tons (a 2.8-percent reduction over the period) in the Extended Policies case relative to the Reference case projection, as compared with 1.7 billion metric tons (a 1.0-percent reduction over the period) in the No Sunset case (Figure 18). The increase in fuel economy standards assumed for new LDVs in the Extended Policies case is responsible for 11.4 percent of the total cumulative reduction in CO_2 emissions from 2011 to 2040 in comparison with the Reference case. The balance of the reduction in CO_2 emissions is a result of greater improvement in appliance efficiencies and increased penetration of renewable electricity generation.

Most of the emissions reductions in the No Sunset case result from increases in renewable electricity generation. Consistent with current EIA conventions and EPA practice, emissions associated with the combustion of biomass for electricity generation are not counted, because they are assumed to be balanced by carbon absorption when the plant feedstock is grown. Relatively small incremental reductions in emissions are attributable to renewables in the Extended Policies case, mainly because electricity demand is lower than in the Reference case, reducing the consumption of all fuels used for generation, including biomass.

In both the No Sunset and Extended Policies cases, water heating, space cooling, and space heating together account for most of the emissions reductions from Reference case levels in the buildings sector. In the industrial sector, the Extended Policies case projects reduced emissions as a result of decreases in electricity purchases and petroleum use.

Figure 17. Electricity generation from natural gas in three cases, 2005-2040 (billion kilowatthours)

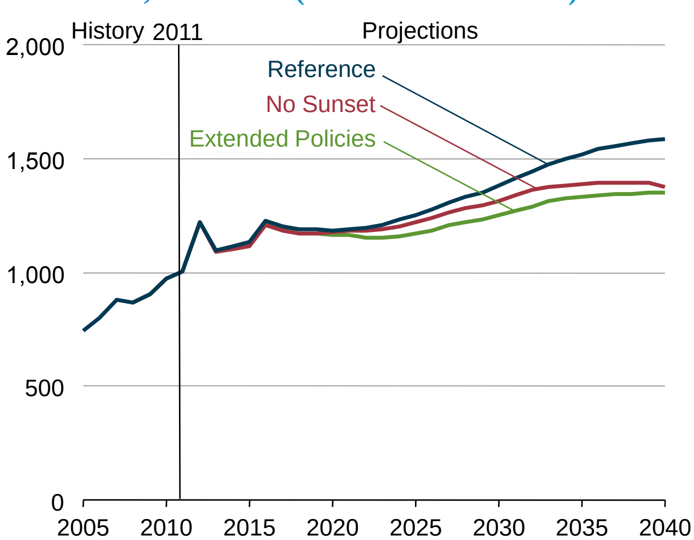
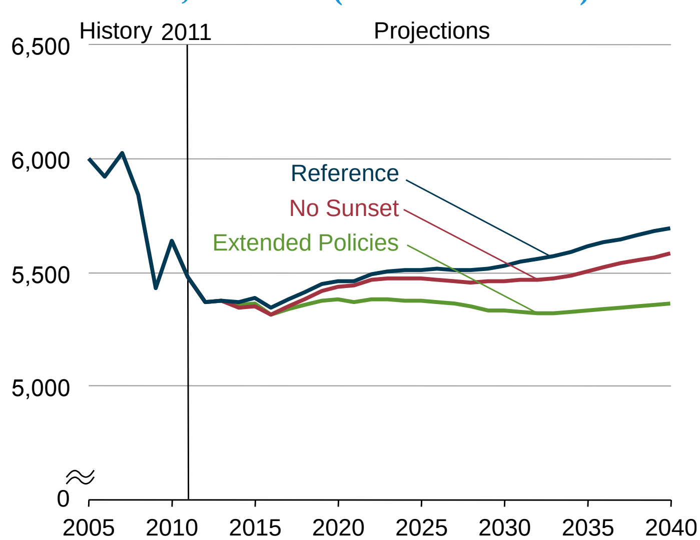


Figure 18. Energy-related carbon dioxide emissions in three cases, 2005-2040 (million metric tons)



Energy prices and tax credit payments

With lower levels of fossil energy use and more consumption of renewable fuels stimulated by tax credits in the No Sunset and Extended Policies cases, energy prices are lower than in the Reference case. In 2040, average delivered natural gas prices (2011 dollars) are $0.29 per million Btu (2.7 percent) and $0.59 per million Btu (5.4 percent) lower in the No Sunset and Extended Policies cases, respectively, than in the Reference case (Figure 19), and electricity prices are 3.9 percent and 6.3 percent lower than in the Reference case (Figure 20).

The reductions in energy consumption and CO_2 emissions in the Extended Policies case are accompanied by higher equipment costs for consumers and revenue reductions for the U.S. government. From 2013 to 2040, residential and commercial consumers spend, on average, an additional $20 billion per year (2011 dollars) for newly purchased end-use equipment, DG systems, and residential building shell improvements in the Extended Policies case as compared with the Reference case. On the other hand, residential and commercial customers save an average of $30 billion per year on energy purchases.

Tax credits paid to consumers in the buildings sector (or, from the government's perspective, reduced revenue) in the No Sunset case average $4 billion (2011 dollars) more per year than in the Reference case, which assumes that existing tax credits expire as currently scheduled, mostly by 2016.

The largest response to federal tax incentives for new renewable generation is seen in the No Sunset case, with extension of the PTC and the 30-percent ITC resulting in annual average reductions in government tax revenues of approximately $2.3 billion from 2011 to 2040, as compared with $650 million per year in the Reference case.

2. Oil price and production trends in *AEO2013*

The benchmark oil price in *AEO2013* is based on spot prices for Brent crude oil (commonly cited as Dated Brent in trade publications), an international benchmark for light sweet crude oil. The West Texas Intermediate (WTI) price has diverged from Brent and other benchmark prices over the past few years as a result of rapid growth in U.S. midcontinent and Canadian oil production, which has overwhelmed the transportation infrastructure needed to move crude oil from Cushing, Oklahoma, where WTI is quoted, to the Gulf Coast. EIA expects the WTI discount to the Brent price level to decrease over time as additional pipeline projects come on line, and will continue to report WTI prices (a critical reference point for the value of growing production in the U.S. midcontinent), as well as imported refiner acquisition costs (IRAC).

AEO2013 projections of future oil supply include two broad categories: petroleum liquids and other liquid fuels. The term petroleum liquids refers to crude oil and lease condensate—which includes tight oil, shale oil, extra-heavy crude oil, and bitumen (i.e., oil sands, either diluted or upgraded), plant condensate, natural gas plant liquids (NGPL), and refinery gain. The term other liquids refers to oil shale (i.e., kerogen-to-liquids), gas-to-liquids (GTL), coal-to-liquids (CTL), and biofuels (including biomass-to-liquids).

The key factors determining long-term supply, demand, and prices for petroleum and other liquids can be summarized in four broad categories: the economics of non-Organization of the Petroleum-Exporting Countries (OPEC) petroleum liquids supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

To reflect the significant uncertainty associated with future oil prices, EIA develops three price cases that examine the potential impacts of different oil price paths on U.S. energy markets (Figure 21). The three price cases are developed by adjusting the four key factors described above. The following sections discuss the adjustments made in *AEO2013*. Each price case represents one of

Figure 19. Average delivered prices for natural gas in three cases, 2005-2040 (2011 dollars per million Btu)

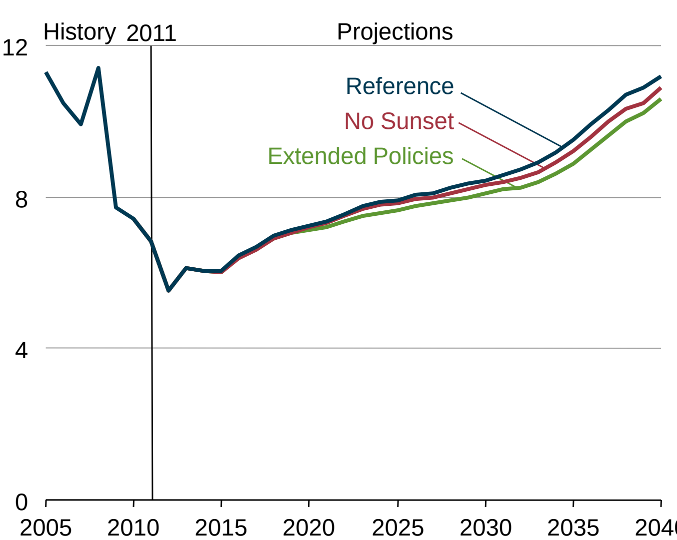
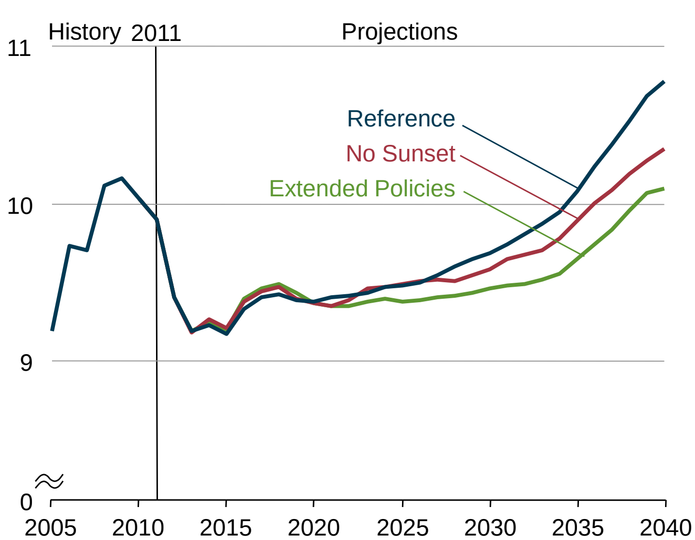


Figure 20. Average electricity prices in three cases, 2005-2040 (2011 cents per kilowatthour)



potentially many combinations of supply and demand that would result in the same price path. EIA does not assign probabilities to any of the oil price cases.

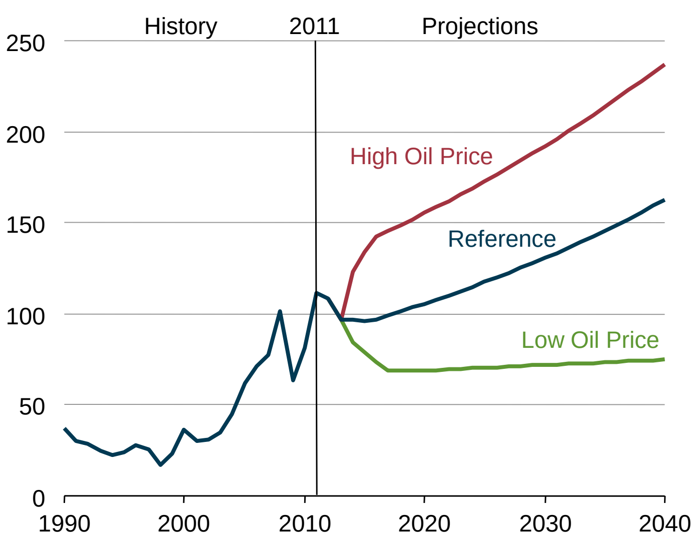
Because EIA's oil price paths represent market equilibrium between supply and demand in terms of annual average prices, they do not show the price volatility that occurs over days, months, or years. As a frame of reference, over the past two decades, volatility within a single year has averaged about 30 percent [*70*]. Although that level of volatility could continue, the alternative oil price cases in *AEO2013* assume smaller near-term price variation than in previous *AEO*s, because larger near-term price swings are expected to lead to market changes in supply or demand that would dampen the price.

The *AEO2013* oil price cases represent internally consistent scenarios of world energy production, consumption, and economics. One interesting outcome of the three oil price cases is that, although the price paths diverge, interactions among the four key factors lead to nearly equal total volumes of world liquids supply in the three cases in the 2030 timeframe (Figure 22).

Reference case

Among the key factors defining the Reference case are the Organization for Economic Cooperation and Development (OECD) and non-OECD gross domestic product (GDP) growth rates and liquid fuels consumption per dollar of GDP. Both the OECD and non-OECD growth rates and liquids fuels consumption per dollar of GDP decline over the projection period in the Reference case. OPEC continues restricting production in a manner that keeps its market share of total liquid fuels production between 39 percent and 43 percent for most of the projection, rising to 43 percent in the final years. Most other liquid fuels production technologies are economical at Reference case prices. In the Reference case, the Brent price declines to $96 per barrel in 2015 and then increases over the remainder of the period, to $163 per barrel in 2040, as a result of demand increases and supply pressures.

Figure 21. Annual average spot price for Brent crude oil in three cases, 1990-2040 (2011 dollars per barrel)



OPEC production in the Reference case grows from 35 million barrels per day in 2011 to 48 million barrels per day in 2040 (Figure 23). Although the OPEC resource base is sufficient to support much higher production levels, the OPEC countries have an incentive to restrict production in order to support higher prices and sustain revenues in the long term. The Reference case assumes that OPEC will maintain a cohesive policy of limiting supply growth, rather than maximizing total annual revenues. The Reference case also assumes that no geopolitical events will cause prolonged supply shocks in the OPEC countries that could further limit production growth.

Non-OPEC petroleum production grows significantly in the early years of the Reference case projection, to 55 million barrels per day in 2020 from 50 million barrels per day in 2011, primarily as a result of increased production from tight oil

Figure 22. World petroleum and other liquids supply in three cases, 1990-2040 (million barrels per day)

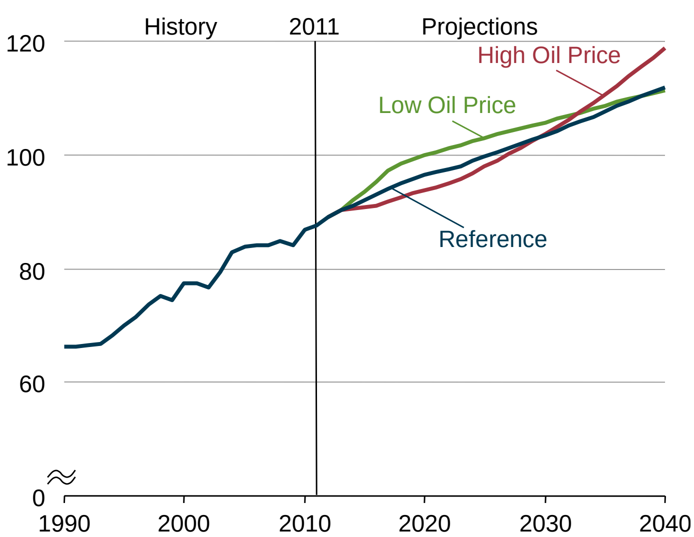
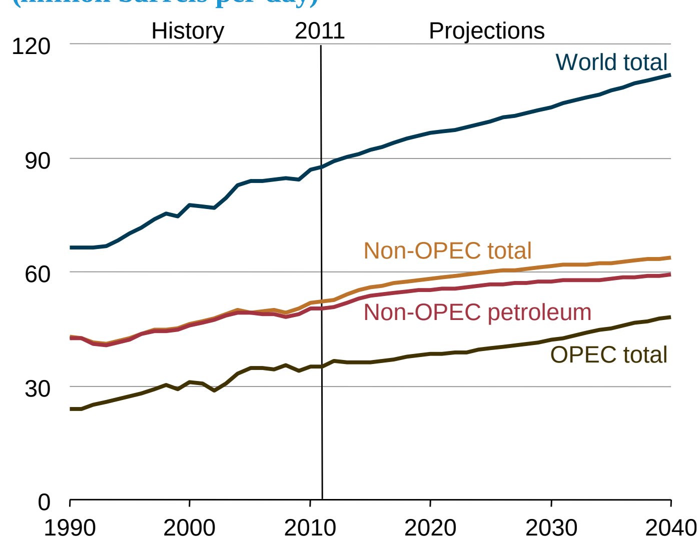


Figure 23. World petroleum and other liquids supply by source in the Reference case, 1990-2040 (million barrels per day)



formations. After 2020, production growth continues at a slower pace, adding another 4 million barrels per day to net production in 2040, with production from new wells increasing slightly faster than the decline in production from existing wells. The growth in non-OPEC production results primarily from the development of new fields and the application of new technologies, such as enhanced oil recovery (EOR), horizontal drilling, and hydraulic fracturing, which increase recovery rates from existing fields. The average cost per barrel of non-OPEC oil production rises as production volumes increase, and the rising costs dampen further production growth.

Non-OPEC production of other liquids grows from 1.8 million barrels per day in 2011 to 4.6 million barrels per day in 2040, as Brent crude oil prices remain sufficiently high to make other liquids production technologies economically feasible. Non-OPEC liquids production in the Reference case totals 58 million barrels per day in 2020, 61 million barrels per day in 2030, and 64 million barrels per day in 2040.

Low Oil Price case

The *AEO2013* Low Oil Price case assumes slower GDP growth for the non-OECD countries than in the Reference case. OPEC is less successful in restricting production in the Low Oil Price case, and as a result its share of total world liquids production increases to 49 percent in 2040. Despite lower Brent prices than in the Reference case, non-OPEC petroleum production levels are maintained at roughly 54 million barrels per day through 2030. After 2030, total non-OPEC production declines as existing fields are depleted and not fully replaced by production from new fields and more costly EOR technologies. With higher average costs for resource development in the non-OPEC countries, the Brent crude oil price in the Low Oil Price case is not sufficient to make all undeveloped fields economically viable. Non-OPEC petroleum production rises slightly in the projection, to 54 million barrels per day, before returning to roughly current levels of 51 million barrels per day in 2040. Non-OPEC production of other liquids grows more rapidly than in the Reference case, and in 2040 it is 25 percent higher than projected in the Reference case.

Brent crude oil prices fall below $80 per barrel in 2015 in the Low Oil Price case and decline further to just below $70 per barrel in 2017, followed by a slow increase to $75 per barrel in 2040. In the near term, extra supply enters the market, and lower economic growth in the non-OECD countries leads to falling prices. The higher levels of OPEC petroleum production assumed in the Low Oil Price case keep prices from increasing appreciably in the long term.

OPEC's ability to support higher oil prices is weakened by its inability to limit production as much as in the Reference case. Lower prices squeeze the revenues of OPEC members, increasing their incentive to produce beyond their quotas. As a result, OPEC liquids production increases to 54 million barrels per day in 2040. The lower prices in the Low Oil Price case cause a decline in OPEC revenue to the lowest level among the three cases, illustrating the relatively strong incentive for OPEC members to restrict supply.

High Oil Price case

In the High Oil Price case, non-OECD GDP growth is more rapid than projected in the Reference case, and liquid fuels consumption per unit of GDP in the non-OECD countries declines more slowly than in the Reference case. Continuing restrictions on oil production keep the OPEC market share of total liquid fuels production between 37 and 40 percent, with total oil production about 1.0 million barrels per day lower than in the Reference case. Despite higher Brent oil prices, non-OPEC petroleum production initially expands at about the same rate as in the Reference case because of limited access to existing resources and lower discovery rates. Non-OPEC production of other liquids grows strongly in response to higher prices, rising to 8 million barrels per day in 2040.

Brent crude oil prices in the High Oil Price case increase to $155 per barrel in 2020 and $237 per barrel in 2040 in reaction to very high demand for liquid fuels in the non-OECD countries. The robust price increase keeps total world demand within the range of expected production capabilities.

3. U.S. reliance on imported liquid fuels in alternative scenarios

Liquid fuels [*71*] play a vital role in the U.S. energy system and economy, and access to affordable liquid fuels has contributed to the nation's economic prosperity. However, the extent of U.S. reliance on imported oil has often been raised as a matter of concern over the past 40 years. U.S. net imports of petroleum and other liquid fuels as a share of consumption have been one of the most-watched indicators in national and global energy analyses. After rising steadily from 1950 to 1977, when it reached 47 percent by the most comprehensive measure, U.S. net import dependence declined to 27 percent in 1985. Between 1985 and 2005, net imports of liquid fuels as a share of consumption again rose, reaching 60 percent in 2005. Since that time, however, the trend toward growing U.S. dependence on liquid fuels imports has again reversed, with the net import share falling to an estimated 41 percent in 2012, and with EIA projecting further significant declines in 2013 and 2014. The decline in net import dependence since 2005 has resulted from several disparate factors, and continued changes in those and other factors will determine how this indicator evolves in the future. Key questions include:

- What are the key determinants of U.S. liquid fuels supply and demand?
- Will the supply and demand trends that have reduced dependence on net imports since 2005 intensify or abate?
- What supply and demand developments could yield an outcome in which the United States is no longer a net importer of liquid fuels?

This discussion considers potential changes to the U.S. energy system that are inherently speculative and should be viewed as what-if cases. The four cases that are discussed include two cases (Low Oil and Gas Resources and High Oil and Gas Resources) in which only the supply assumptions are varied, and two cases (Low/No Net Imports and High Net Imports) in which both supply and demand assumptions change. The changes in these cases generate wide variation from the liquid fuels import dependence values seen in the *AEO2013* Reference case, but they should not be viewed as spanning the range of possible outcomes. Cases in which both supply and demand assumptions are modified show the greatest changes. In the Low/No Net Imports case, the United States ceases to be a net liquid fuels importer in the mid-2030s, and by 2040 U.S. net exports are 8 percent of total U.S. liquid fuel production. In contrast, in the High Net Imports case, net petroleum import dependence is above 44 percent in 2040, higher than the Reference case level of 37 percent but still well below the 60-percent level seen in 2005. Cases in which only supply assumptions are varied show intermediate levels of change in liquid fuels import dependence.

As the case names suggest, the Low Oil and Gas Resource case incorporates less-optimistic oil and natural gas resource assumptions than those in the Reference case, while the High Oil and Gas Resource case does the opposite. The other two cases combine different oil and natural gas resource assumptions with changes in assumptions that influence the demands for liquid fuels. The Low/No Net Imports case simulates an environment in which U.S. energy production grows rapidly while domestic consumption of liquid fuels declines. Conversely, the High Net Imports case combines the Low Oil and Gas Resource case assumptions with demand-related assumptions including slower improvements in vehicle efficiency, higher levels of vehicle miles traveled (VMT) relative to the Reference case, and reduced use of alternative transportation fuels.

Resource assumptions

A key contributing factor to the recent decline in net import dependence has been the rapid growth of U.S. oil production from tight onshore formations, which has followed closely after the rapid growth of natural gas production from similar types of resources. Projections of future production trends inevitably reflect many uncertainties regarding the actual level of resources available, the difficulty in extracting them, and the evolution of the technologies (and associated costs) used to recover them. To represent these uncertainties, the assumptions used in the High and Low Oil and Gas Resource cases represent significant deviations from the Reference case.

Estimates of technically recoverable resources from the rapidly developing tight oil formations are particularly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. Over the past decade, as more tight and shale formations have gone into commercial production, estimates of technically and economically recoverable resources have generally increased. Technically recoverable resource estimates, however, embody many assumptions that might not prove to be true over the long term, over the entire range of tight or shale formations, or even within particular formations. For example, the tight oil resource estimates in the Reference case assume that production rates achieved in a limited portion of a given formation are representative of the entire formation, even though neighboring tight oil well production rates can vary widely. Any specific tight or shale formation can vary significantly across the formation with respect to relevant characteristics [*72*], resulting in widely varying rates of well production. The application of refinements to current technologies, as well as new technological advancements, can also have a significant but highly uncertain impact on the recoverability of tight and shale crude oil.

As shown in Table 5, the High and Low Oil and Gas Resource cases were developed with alternative crude oil and natural gas resource assumptions giving higher and lower technically recoverable resources than assumed in the Reference case. While these cases do not represent upper and lower bounds on future domestic oil and natural gas supply, they allow for an examination of the potential effects of higher and lower domestic supply on energy demand, imports, and prices.

The Low Oil and Gas Resource case only reflects the uncertainty around tight oil and shale gas resources. The resource estimates in the Reference case are based on crude oil and natural gas production rates achieved in a limited portion of the tight or shale formation and are assumed to be representative of the entire formation. However, the variability in formation characteristics described earlier can also affect the estimated ultimate recovery (EUR) of wells. For the Low Oil and Gas Resource case, the EUR per tight and shale well is assumed to be 50 percent lower than in the *AEO2013* Reference case. All other resource assumptions are unchanged from the Reference case.

The High Oil and Gas Resource case reflects a broad-based increase in crude oil and natural gas resources. Optimism regarding increased supply has been buoyed by recent advances in crude oil and natural gas production that resulted in an unprecedented annual increase in U.S. crude oil production in 2012. The *AEO2013* Reference case shows continued near-term production growth followed by a decline in U.S. production after 2020. The High Oil and Gas Resource case presents a scenario in which U.S. crude oil production continues to expand after about 2020 due to assumed higher technically recoverable tight oil resources, as well as undiscovered resources in Alaska and the offshore Lower 48 states. In addition, the maximum annual penetration rate for GTL technology is doubled compared to the Reference case.

The tight and shale resources are increased by changing both the EUR per well and the well spacing. A doubling in tight and shale well EUR, when assumed to occur through raising the production type curves [*73*] across the board, is responsible for the significantly faster increases in production and is also a contributing factor in avoiding the production decline during the projection period. This assumption change is quite optimistic and may alternatively be considered as a proxy for other changes or combinations of changes that have yet to be observed.

Although initial production rates have increased over the past few years, it is too early to conclude that overall EURs have increased and will continue to increase. Instead, producers may just be recovering the resource more quickly, resulting in a more dramatic decline in production later, with little impact on the well's overall EUR. The decreased well spacing reflects less the capability to drill wells closer together (i.e., avoid interference) and instead more the discovery of and production from other shale plays that are not yet in commercial development. These may either be stacked in the same formation or reflect future technological innovations that would bring into production plays that are otherwise not amenable to current hydraulic fracturing technology.

Other resources also are assumed to contribute to supply, as technological or other unforeseen changes improve their prospects. The resource assumptions for the offshore Lower 48 states in the High Oil and Gas Resource case reflect the possibility that resources may be substantially higher than assumed in the Reference case. Resource estimates for most of the U.S. Outer Continental Shelf are uncertain, particularly for resources in undeveloped regions where there has been little or no exploration and development activity, and where modern seismic survey data are lacking [*74*]. The increase in crude oil resources in Alaska reflects the possibility that there may be more crude oil on the North Slope, including tight oil. It does not, however, reflect an opening of the Arctic National Wildlife Refuge to exploration or production activity. Finally, modest production from kerogen (oil shale) resources, which remains below 140,000 barrels per day through the 2040 projection horizon, is included in the High Oil and Gas Resource case.

Table 5. Differences in crude oil and natural gas assumptions across three cases

	Reference			
Resource	Average	Range	Low Oil and Gas Resource	High Oil and Gas Resource
Shale gas, tight gas, and tight oil				
Estimated Ultimate Recovery				
Shale gas (billion cubic feet per well)	1.04	0.01-11.32	50% lower	100% higher
Tight gas (billion cubic feet per well)	0.5	0.01-11.02	50% lower	100% higher
Tight oil (thousand barrels per well)	135	1-778	50% lower	100% higher
Incremental technically recoverable resource				
Natural gas (trillion cubic feet)	--	--	(522)	1,044
Crude oil (billion barrels)	--	--	(29)	58
Well spacing (acres)	100	20-406	No change	20-40
Incremental technically recoverable resource				
Natural gas (trillion cubic feet)	--	--	No change	3,601
Crude oil (billion barrels)	--	--	No change	269
Alaska				
North Slope onshore & offshore				
Offshore production start year	2029		No change	2025
Undiscovered crude oil (billion barrels)	22		No change	50% higher
Incremental technically recoverable resource (billion barrels)	--		No change	11
Tight oil technically recoverable resource (billion barrels)	None		No change	1.9
Lower 48 states				
Offshore undiscovered resources				
Crude oil (billion barrels)	40		No change	50% higher
Natural gas (trillion cubic feet)	208		No change	50% higher
Incremental technically recoverable resource				
Natural gas (trillion cubic feet)	--		No change	104
Crude oil (billion barrels)	--		No change	20
Kerogen (oil shale)				
Technically recoverable resource	--		No change	No change
2040 production (thousand barrels per day)	None		None	135

Demand assumptions

Reductions in demand for liquid fuels in some uses, such as personal transportation and home heating, coupled with slow growth in other applications, have been another key contributing factor in the decline of the nation's net dependence on imported liquid fuels since 2005. As with supply assumptions, the key analytic assumptions that drive future trends in liquid fuels demand in EIA's projections are subject to considerable uncertainty. The most important assumptions affecting future demand for liquids fuels include:

- The future level of activities that use liquid fuels, such as VMT
- The future efficiency of equipment that uses liquid fuels, such as automobiles, trucks, and aircraft
- The future extent of fuel switching that replaces liquid fuels with other fuel types, such as liquefied natural gas (LNG), biofuels, or electricity.

Two alternative sets of demand assumptions that lead to higher or lower demand for liquid fuels than in the *AEO2013* Reference case are outlined below. The two alternative scenarios are then applied in conjunction with the High and Low Oil and Gas Resource cases to develop the Low/No Net Import and High Net Import cases.

Vehicle miles traveled

Projected fuel use by LDVs is directly proportional to light-duty VMT, which can be influenced by policy, but it is driven primarily by market factors, demography, and consumer preferences. All else being equal, VMT is more likely to grow when the driving-age population is growing, economic activity is robust, and fuel prices are moderate. For example, there is a strong linkage between economic activity, employment, and commuting. In addition, there is a correlation between income and discretionary travel that reinforces the economy-VMT link. Turning to demography, factors such as the population level, age distribution, and household composition are perhaps most important for VMT. For example, lower immigration would lead to a smaller U.S. population over time, lowering VMT. The aging of the U.S. population continues and will also have long-term effects on VMT trends, as older drivers do not behave in the same ways as younger or middle-aged drivers. At times, the factors that influence VMT intertwine in ways that change long-term trends in U.S. driving and fuel consumption. For example, the increase in two-income families that occurred beginning in the 1970s created a surge in VMT that involved both economic activity and demographics.

Alternative modes of travel affect VMT to the degree that the population substitutes other travel services for personal LDVs. The level of change is related to the cost, convenience, and geographic extent of mass transit, rail, biking, and pedestrian travel service options. Car-sharing services, which have grown in popularity in recent years, could discourage personal vehicle VMT by putting more of the cost of incremental vehicle use on the margin when compared with traditional vehicle ownership or leasing, where many of the major costs of vehicle use are incurred at the time a vehicle is acquired, registered, and insured. Improvements in the fuel efficiency of vehicles, however, could increase VMT by lowering the marginal costs of driving. In recent analyses supporting the promulgation of new final fuel economy and GHG standards for LDVs in MY 2017 through 2025, NHTSA and EPA applied a 10-percent rebound in travel to reflect the lower fueling costs of more efficient vehicles [*75*]. Both higher and lower values for the rebound have been advanced by various analysts [*76*].

Other types of technological change also can affect projected VMT growth. E-commerce, telework, and social media can supplant (or complement) personal vehicle use. Some analysts have suggested an association between rising interest in social media and a decline in the rates at which driving-age youth secure driver licenses; however, that decline also could be related to recent weakness in the economy.

Many of the factors reviewed above were also addressed in the August 2012 National Petroleum Council Future Transportation Fuels study [*77*]. That study considered numerous specific research efforts, as well as available summaries of the literature on VMT, and concluded that the economic and demographic factors remain dominant. The VMT scenario adopted for most of the analysis in that study reflected declining compound annual growth rates of VMT over time, with the growth rate in VMT, which was 3.1 percent in the 1971-1995 and 2.0 percent in the 1996-2007 periods, falling to under 1 percent after 2035.

In the *AEO2013* Reference case, the compound annual rate of growth in light-duty VMT over the period from 2011 to 2040 is 1.2 percent—well below the historical record through 2005 but significantly higher than the average annual light-duty VMT growth rate of 0.7 percent from 2005 through 2011. The 2005-2011 period was marked by generally poor economic performance, high unemployment, and high liquid fuel prices, all of which likely contributed to lower VMT growth. While VMT growth rates are expected to rise as the economy and employment levels improve, it remains to be seen to what extent such effects might be counteracted or reinforced by some of the other market factors identified above.

The low demand scenario used in the Low/No Net Imports case holds the growth rate of light-duty VMT over the 2011-2040 period at 0.2 percent per year, lower than its 2005-2011 growth rate. The application of a lower growth rate over a 29-year projection period results in total light-duty VMT 26 percent below the Reference case level in 2040. With population growth at 0.9 percent per year, this implies a decline of 0.7 percent per year in VMT per capita. VMT per licensed driver, which increases by 0.3 percent per year in the *AEO2013* Reference case, declines at a rate of 0.8 percent per year in the Low/No Net Imports case. In the High Net Imports case, which assumes more robust demand than in the Reference case, the VMT projection remains close to that in the Reference case, with higher demand resulting from other factors.

Vehicle efficiencies

Turning to vehicle efficiency, the rising fuel economy of new LDVs already has contributed to recent trends in liquid fuels use. Looking forward, the EPA and NHTSA have established joint CAFE and GHG emissions standards through MY 2025. The new CAFE standards result in a fuel economy, measured as a program compliance value, of 47.3 mpg for new LDVs in 2025, based on the distribution of production of passenger cars and light trucks by footprint in *AEO2013*. The EPA and NHTSA also have established a fuel efficiency and GHG emissions program for medium- and heavy-duty vehicles for MY 2014-18. The fuel consumption standards for MY 2014-15 set by NHTSA are voluntary, while the standards for MY 2016 and beyond are mandatory, except those for diesel engines, which are mandatory starting in 2017.

The *AEO2013* Reference case does not consider any possible reduction in fuel economy standards resulting from the scheduled midterm review of the CAFE standards for MY 2023-25, or for any increase in fuel economy standards that may be put in place for model years beyond 2025. The low demand scenario in this article adopts the assumption that post-2025 LDV CAFE standards increase at an average annual rate of 1.4 percent, the same assumption made in the *AEO2013* Extended Policies case. In contrast, the high demand scenario assumes some reduction in current CAFE standards following the scheduled midterm review.

Fuel switching

In the *AEO2013* Reference case, fuel switching to natural gas in the form of compressed natural gas (CNG) and LNG already is projected to achieve significant penetration of natural gas as a fuel for heavy-duty trucks. In the Reference case, natural gas use in heavy-duty vehicles increases to 1 trillion cubic feet per year in 2040, displacing 0.5 million barrels per day of diesel use. The use of natural gas in the Reference case is economically driven. Even after the substantial costs of liquefaction or compression, fuel costs for LNG or CNG are expected to be well below the projected cost of diesel fuel on an energy-equivalent basis. The fuel cost advantage is expected to be large enough in the view of a significant number of operators to offset the considerably higher acquisition costs of vehicles equipped to use these fuels, in addition to offsetting other disadvantages, such as reduced maximum range without refueling, a lower number of refueling locations, reduced volume capacity in certain applications, and an uncertain resale market for vehicles using alternative fuels. For purposes of the low demand scenario for liquid fuels, factors limiting the use of natural gas in heavy-duty vehicles are assumed to be less significant, allowing for higher rates of market penetration.

Natural gas could also prove to be an attractive fuel in other transportation applications. The use of LNG as a fuel for rail transport, which had earlier been considered for environmental reasons, is now under active consideration by major U.S. railroads for economic reasons, motivated by the same gap between the cost of diesel fuel and LNG now and over the projection period. Because all modern railroad locomotives use electric motors to drive their wheels, a switch from diesel to LNG would entail the use of a different fuel to drive the onboard electric generation system. Retrofits have been demonstrated, but new locomotives with generating units specifically optimized for LNG could prove to be more attractive. Because railroads already maintain their own on-system refueling infrastructure, they may be less subject to the concern that truckers considering a switch to alternative fuel vehicles might have regarding the risks that natural gas refueling systems they require would not actually be built. The high concentration of ownership in the U.S. railroad industry could also facilitate a rapid switch toward LNG refueling, with the associated transition to new equipment, under the right circumstances because there are only a few owners making the decisions.

Marine operators have traditionally relied on oil-based fuels, with large oceangoing vessels almost exclusively fueled with heavy high-sulfur fuel oil that typically sells at a discount relative to other petroleum products. Under the International Maritime Organization's International Convention on the Prevention of Pollution from Ships agreement (MARPOL Annex VI) [*78*], the use of heavy high-sulfur fuel oil in international shipping started being phased out for environmental reasons in 2010. Although LNG is one possible option, there are many cost and logistical challenges, including the high cost of retrofits, the long lifetime of existing vessels, and relatively low utilization rates for many routes that will have adverse impacts on the economics of marine LNG refueling infrastructure. Unlike the heavy-duty truck market, there has not yet been an LNG-fueled product offered for general use by manufacturers of marine or rail equipment, making cost and performance comparisons inherently speculative.

In addition to the demand assumptions discussed above, other assumption changes were made to capture potential shifts in vehicle cost and consumer preference for LDVs powered by alternative fuels. In the Low/No Net Imports case, the costs of efficiency technologies and battery technologies were lowered, and the market penetration of E85 fuel was increased, relative to the Reference case levels. With regard to E85, assumptions about consumer preference for flex-fuel vehicles were altered to allow for increases in vehicle sales and E85 demand, leading to greater use of domestically-produced biofuel than projected in the Reference case.

Table 6 summarizes the demand-side assumptions in the alternative demand scenarios for liquid fuels. As with the supply assumptions, the assumptions used in the higher and lower demand cases represent substantial deviations from the *AEO2013* Reference case, and they might instead be realized in terms of other, as-yet-unforeseen developments in technology, economics, or policy.

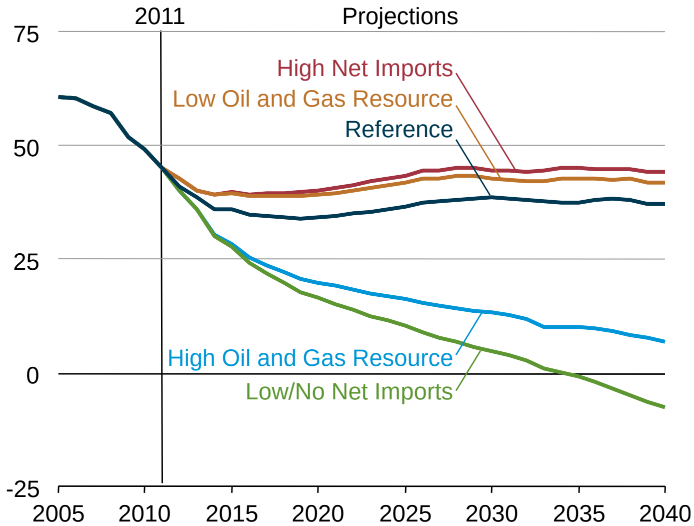
Results

The cases considered show how the future share of net imports in total U.S. liquid fuel use varies with changes in assumptions about the key factors that drive domestic supply and demand for liquid fuels (Figure 24). Some of the assumptions in the Low/No Net imports case, such as assumed increases in LDV fuel economy after 2025 and access to offshore resources, could be influenced by future energy policies. However, other assumptions in this case, such as the greater availability of onshore technically recoverable oil and natural gas resources, depend on geological outcomes that cannot be influenced by policy measures; and economic, consumer, or technological factors may likewise be unaffected or only slightly affected by policy measures.

Net imports and prices

In the Low/No Net Imports case, U.S. net imports of liquid fuels are eliminated in the mid-2030s, and the United States becomes a modest net exporter of those fuels by 2040. As discussed above, this case combines optimistic assumptions about the availability of domestic oil and natural gas resources with assumptions that lower demand for liquid fuels, including a decline in VMT per capita, increased switching to natural gas fuels for transportation (including heavy-duty trucks, rail, boats, and ships), continued significant improvements in the fuel efficiency of new vehicles beyond 2025, wider availability and lower costs of electric battery technologies, and greater market penetration of biofuels and other nonpetroleum liquids. Although other combinations of assumptions, or unforeseen technology breakthroughs, might produce a comparable outcome, the assumptions in the Low/No Net Imports case illustrate the magnitude and type of changes that would be required for the United States to end its reliance on net imports of liquid fuels, which began in 1946 and has continued to the present day. Moreover, regardless of how much the United States is able to reduce its reliance on imported liquids, it will not be entirely insulated from price shocks that affect the global oil market [79].

Figure 24. Net import share of liquid fuels in five cases, 2005-2040 (percent)



As shown in Figure 24, the supply assumptions of the High Oil and Gas Resource case alone result in a decline in net import dependence to 7 percent in 2040, compared to 37 percent in the Reference case, with U.S. crude oil production rising to 10.2 million barrels per day in 2040, or 4.1 million barrels per day above the Reference case level. Tight oil production accounts for more than 77 percent (or 3 million barrels per day) of the difference in production between the two cases. Production of NGL in the United States also exceeds the Reference case level.

Table 6. Differences in transportation demand assumptions across three cases

Transportation mode	Reference	Low/No Net Imports	High Net Imports
Light-duty vehicles			
Vehicle miles traveled (compound annual growth rate, 2011-2040)	1.2%	0.2%	1.1%
Vehicle technology efficiency in 2040	Baseline	Baseline + 10%	Baseline - 10%
Vehicle technology cost in 2040	Baseline	Baseline - 10%	Baseline + 10%
CAFE standard compliance value in 2040 (miles per gallon)	49.0	57.7	39.9
Flex-fuel vehicle stock in 2040 (millions)	20.9	44.3	20.0
Battery-electric vehicle costs	Baseline	Baseline - 14%	Baseline
Heavy-duty vehicles			
Vehicle technology efficiency in 2040	Baseline	Baseline + 10%	Baseline - 10%
Vehicle technology cost in 2040	Baseline	Baseline - 10%	Baseline + 10%
Potential market share for natural gas fuel	27%	41%	27%
Marine			
Efficiency (ton-miles per thousand Btu)	2.55	2.66	2.41
Potential market share for natural gas fuel	0%	8%	0%
Rail			
Efficiency (ton-miles per thousand Btu)	3.54	3.70	3.44
Potential market share for natural gas fuel	0%	100%	0%

As a result of higher U.S. liquid fuels production, Brent crude oil prices in the High Oil and Gas Resource case are lower than in the Reference case, which also lowers motor gasoline and diesel prices to the transportation sector, encouraging greater consumption and partially dampening the projected decline in net dependence on liquid fuel imports. In the High Oil and Gas Resource case, the reduction in motor fuels prices increases fuel consumption in 2040 by 350 thousand barrels per day in the transportation sector and 230 thousand barrels per day in the industrial sector, which accounts for nearly all of the increase in total U.S. liquid fuels consumption (600 thousand barrels per day) relative to the Reference case total in 2040.

Global market, the economy, and refining

The addition of assumptions that slow the growth of demand for liquid fuels in the Low/No Net Imports case more than offsets the increase in demand that results from lower liquid fuel prices, so that total liquid fuels consumption in 2040 is 2.1 million barrels per day lower than projected in the Reference case. The combination of high crude oil and natural gas resources and lower demand for liquid fuels pushes Brent crude oil prices to $29 per barrel below the Reference case level in 2040. However, given the cumulative impact of factors that tend to raise world oil prices in real terms over the projection period, inflation-adjusted crude oil prices in the Low/No Net Imports case are still above today's price level.

One of the most uncertain aspects of the analysis concerns the effect on the global market for liquid fuels, which is highly integrated. Although the analysis reflects price effects that are based on the relative scale of the changes in U.S. domestic supply and net U.S. imports of liquid fuels within the overall international crude oil market, strategic choices made by the leading oil-exporting countries could result in price and quantity effects that differ significantly from those presented here. Moreover, regardless of how much the United States reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices if current policies and regulations remain in effect and world markets for crude oil streams of sulfur quality remain closely aligned absent transportation bottlenecks [*80*].

Although the focus is mainly on liquid fuels markets, the more optimistic resource assumptions in the High Oil and Gas Resource case also lead to more natural gas production. The higher productivity of shale and tight gas wells puts downward pressure on natural gas prices and thus encourages increased domestic consumption of natural gas (38 trillion cubic feet in the High Oil and Gas Resource case, compared to 30 trillion cubic feet in the Reference case in 2040) and higher net exports (both pipeline and LNG) of natural gas. As a result, projected domestic natural gas production in 2040 is considerably higher in the High Oil and Gas Resource case (45 trillion cubic feet) than in the Reference case (33 trillion cubic feet).

The Low Oil and Gas Resource case illustrates the implications of an outcome in which U.S. oil and gas resources turn out to be smaller than expected in the Reference case. In this case, domestic crude oil production peaks in 2016 at 6.9 million barrels per day, declines to 5.9 million barrels per day in 2028, and remains relatively flat (between 5.8 and 6.0 million barrels per day) through 2040. The lower well productivity in this case puts upward pressure on natural gas prices, resulting in lower natural gas consumption and production. In 2040, U.S. natural gas production is 27 trillion cubic feet in the Low Oil and Gas Resource case, compared with 33 trillion cubic feet in the Reference case.

These alternative cases may also have significant implications for the broader economy. Liquid fuels provide power and raw materials (feedstocks) for a substantial portion of the U.S. economy, and the macroeconomic impacts of both the High Oil and Gas Resource case and the Low/No Net Imports case suggest that significant economic benefits would accrue if some version of those futures were realized (see discussion of NGL later in "Issues in focus"). This is in spite of the fact that petroleum remains a global market in each of the scenarios, which limits the price impacts for gasoline, diesel, and other petroleum-derived fuels. In the High Oil and Gas Resource case, increasing energy production has immediate benefits for the economy. U.S. industries produce more goods with 12 percent lower energy costs in 2025 and 15 percent lower energy costs in 2040. Consumers see roughly 10 percent lower energy prices in 2025, and 13 percent lower energy prices in 2040, as compared with the Reference case. Cheaper energy allows the economy to expand further, with real GDP attaining levels that are on average about 1 percent above those in the Reference case from 2025 through 2040, including growth in both aggregate consumption and investment.

The alternative cases also imply substantial changes in the future operations of U.S. petroleum refineries, as is particularly evident in the Low/No Net Imports case. Drastically reduced product consumption and increased nonpetroleum sources of transportation fuels, taken in isolation, would tend to reduce utilization of U.S. refineries. The combination of higher domestic crude supply and reduced crude runs in the refining sector would sharply reduce or eliminate crude oil imports and could potentially create market pressure for crude oil exports to balance crude supply with refinery runs. However, under current laws and regulations, crude exports require licenses that have not been issued except in circumstances involving exports to Canada or exports of limited quantities of specific crude streams, such as California heavy oil [*81*].

Rather than assuming a change in current policies toward crude oil exports, and recognizing the high efficiency and low operating costs of U.S. refineries relative to global competitors in the refining sector, exports of petroleum products, which are not subject to export licensing requirements, rise significantly to avoid the uneconomical unloading of efficient U.S. refinery capacity, continuing a trend that has already become evident over the past several years. Product exports rise until the incremental refining value of crude oil processed is equivalent to the cost of crude imports. To balance the rest of the world as a result of increased U.S. product exports, it is assumed that the increased volumes of U.S. liquid fuel product exports would result in a decrease in the volume of the rest of the world's crude runs, and that world consumption, net of U.S. exports, would also be reduced by an amount necessary to keep demand and supply volumes in balance.

Projected carbon dioxide emissions

Total U.S. CO_2 emissions show the impacts of changing fuel prices through all the sectors of the economy. In the High Oil and Gas Resource case, the availability of more natural gas at lower prices encourages the electric power sector to increase its reliance on natural gas for electricity generation. Coal is the most affected, with coal displaced over the first part of the projection, and new renewable generation sources also affected after 2030 or so, resulting in projected CO_2 emissions in the High Oil and Gas Resource case that exceed those in the Reference case after 2035 (Figure 25). With less-plentiful and more-expensive natural gas in the Low Oil and Gas Resource and High Net Imports cases, the reverse is true, with fewer coal retirements leading to higher CO_2 emissions than in the Reference case early in the projection period. Later in the projection, however, the electric power sector turns first to renewable technologies earlier in the Low Oil and Gas Resource and High Net Imports cases, and after 2030 invests in more nuclear plants, reducing CO_2 emissions from the levels projected in the Reference case. In the Low Oil and Gas Resource case, CO_2 emissions are lower than in the Reference case starting in 2026. In the Low/No Net Imports case, annual CO_2 emissions from the transportation sector continue to decline as a result of reduced travel demand; these emissions are conversely higher in the High Net Imports case. Figure 25 summarizes the CO_2 emissions projections in the cases completed for this analysis.

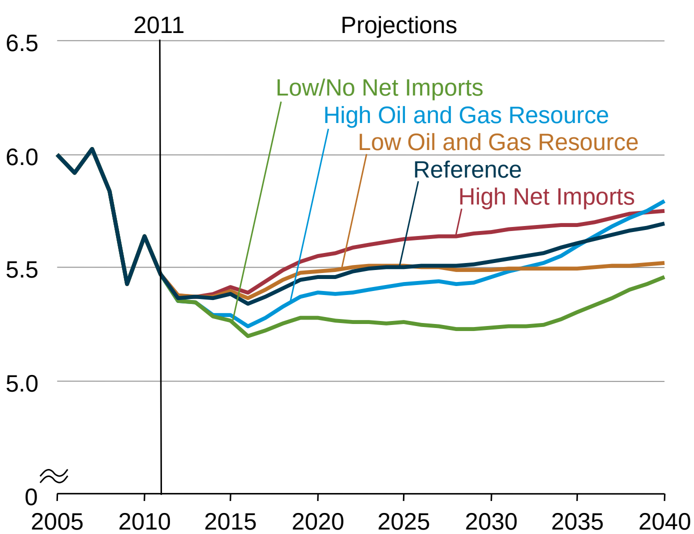
4. Competition between coal and natural gas in the electric power sector

Over the past 20 years, natural gas has been the go-to fuel for new electricity generation capacity. From 1990 to 2011, natural gas-fired plants accounted for 77 percent of all generating capacity additions, and many of the plants added were very efficient combined-cycle plants. However, with slow growth in electricity demand and spikes in natural gas prices between 2005 and 2008, much of the added capacity was used infrequently. Since 2009 natural gas prices have been relatively low, making efficient natural gas-fired combined-cycle plants increasingly competitive to operate in comparison with existing coal-fired plants, particularly in the Southeast and other regions where they have been used to meet demand formerly served by coal-fired plants. In 2012, as natural gas prices reached historic lows, there were many months when natural gas displacement of coal-fired generation was widespread nationally.

In the *AEO2013* Reference case, the competition between coal and natural gas in electricity generation is expected to continue in the near term, particularly in certain regions. However, because natural gas prices are projected to increase more rapidly than coal prices, existing coal plants gradually recapture some of the market lost in recent years. Natural gas-fired plants continue to be the favored source for new generating capacity over much of the projection period because of their relatively low costs and high efficiencies. The natural gas share of total electricity generation increases in the Reference case from 24 percent in 2011 to 30 percent in 2040. Coal remains the largest source of electricity generation, but its share of total electricity generation, which was 51 percent in 2003, declines from 42 percent in 2011 to 35 percent in 2040.

At any point, short-term competition between existing coal- and gas-fired generators—i.e., the decisions determining which generators will be dispatched to generate electricity—depends largely on the relative operating costs for each type of generation, of which fuel costs are a major portion. A second aspect of competition occurs over the longer term, as developers choose which fuels and technologies to use for new capacity builds and whether or not to make mandated or optional upgrades to existing plants. The natural gas or coal share of total generation depends both on the available capacity of each fuel type (affected by the latter type of competition) and on how intensively the capacity is operated.

Figure 25. U.S. carbon dioxide emissions in five cases, 2005-2040 (billion metric tons)



There is significant uncertainty about future coal and natural gas prices, as well as about future growth in electricity demand, which determines the need for new generating capacity. In *AEO2013*, alternative cases with higher and lower coal and natural gas prices and variations in the rate of electricity demand growth are used to examine the potential impacts of those uncertainties. The alternative cases illustrate the influence of fuel prices and demand on dispatch and capacity planning decisions.

Recent history of price-based competition

In recent years, natural gas has come into dispatch-level competition with coal as the cost of operating natural gas-fired generators has neared the cost of operating coal-fired generators. A number of factors led to the growing competition, including:

- A build-out of efficient combined-cycle capacity during the early 2000s, which in general was used infrequently until recently

- Expansion of the natural gas pipeline network, reducing uncertainty about the availability of natural gas
- Gains in natural gas production from domestic shale formations that have contributed to falling natural gas prices
- Rising coal prices.

Until mid-2008, coal-fired generators were cheaper to operate than natural gas-fired generators in most applications and regions. Competition between available natural gas combined-cycle generators (NGCC) and generators burning eastern (Appalachian) and imported coal began in southeastern electric markets in 2009. Rough parity between NGCC and more expensive coal-fired plants continued until late 2011, when increased natural gas production led to a decline in the fuel price and, in the spring of 2012, a dramatic increase in competition between natural gas and even less expensive types of coal. With natural gas-fired generation increasing steadily, the natural gas share of U.S. electric power sector electricity generation was almost equal to the coal share for the first time in April 2012.

The following discussion focuses on the electric power sector, excluding other generation sources in the residential, commercial, and industrial end-use sectors. The industrial sector in particular may also respond to changes in coal and natural gas fuel prices by varying their level of development, but industrial users typically do not have the option to choose between the fuels as in the power sector, and there are fewer opportunities for direct competition between coal and natural gas for electricity generation.

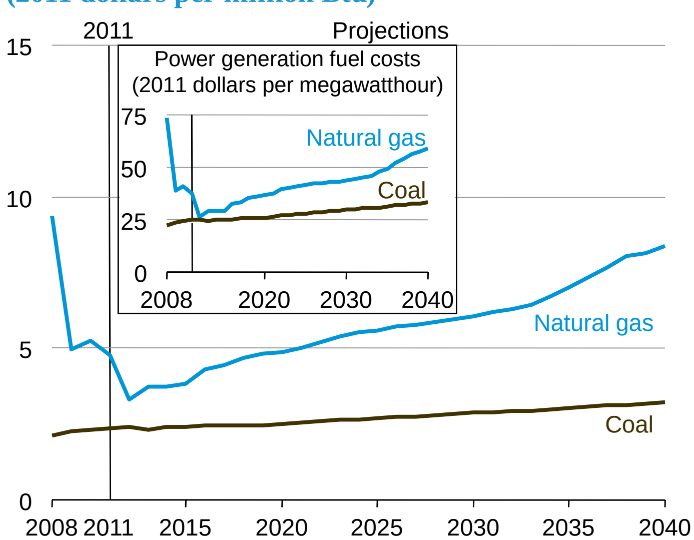
Outlook for fuel competition in power generation

The difference between average annual prices per million Btu for natural gas and coal delivered to U.S. electric power plants narrowed substantially in 2012, so that the fuel costs of generating power from NGCC units and coal steam turbines per megawatthour were essentially equal on a national average basis (Figure 26), given that combined-cycle plants are much more efficient than coal-fired plants. When the ratio of natural gas prices to coal prices is approximately 1.5 or lower, a typical natural gas-fired combined-cycle plant has lower generating costs than a typical coal-fired plant. In the Reference case projection, natural gas plants begin to lose competitive advantage over time, as natural gas prices increase relative to coal prices. Because fuel prices vary by region, and because there is also considerable variation in efficiencies across the existing fleet of both coal-fired and combined-cycle plants, dispatch-level competition between coal and natural gas continues.

In the Reference case, coal-fired generation increases from 2012 levels and recaptures some of the power generation market lost to natural gas in recent years. The extent of that recovery varies significantly, however, depending on assumptions about the relative prices of the two fuels. The following alternative cases, which assume higher or lower availability or prices for natural gas and coal than in the Reference case are used to examine the likely effects of different market conditions:

- The Low Oil and Gas Resource case assumes that the EUR per shale gas, tight gas, or tight oil well is 50 percent lower than in the Reference Case. In 2040, delivered natural gas prices to the electric power sector are 26 percent higher than in the Reference case.
- The High Oil and Gas Resource case assumes that the EUR per shale gas, tight gas, or tight oil well is 100 percent higher than in the Reference case, and the maximum well spacing for shale gas, tight gas, and tight oil plays is assumed to be 40 acres. This case also assumes that the EUR for wells in the Alaska offshore and the Federal Gulf of Mexico is 50 percent higher than in the Reference case, that there is development of kerogen resources in the lower 48 states, and that the schedule for development of Alaskan resources is accelerated. In 2040, delivered natural gas prices are 39 percent lower than projected in the Reference case.

Figure 26. Average delivered fuel prices to electric power plants in the Reference case, 2008-2040 (2011 dollars per million Btu)



- The High Coal Cost case assumes lower mine productivity and higher costs for labor, mine equipment, and coal transportation, which ultimately result in higher coal prices for electric power plants. In 2040, the delivered coal price is 77 percent higher than in the Reference case.
- The Low Coal Cost case assumes higher mining productivity and lower costs for labor, mine equipment, and coal transportation, leading to lower coal prices for electric power plants. In 2040, the delivered coal price is 41 percent lower than in the Reference case.

Figure 27 compares the ratio of average per-megawatthour fuel costs for NGCC plants and coal steam turbines at the national level across the cases. It illustrates the relative competitiveness of dispatching coal-fired steam turbines versus NGCC plants, including the differences in efficiency (heat rates) of the two types of generators. The ratio of natural gas to coal would be about 1.5 without considering the difference in efficiency. Higher coal prices or lower natural gas prices move the ratio closer to the line of competitive parity, where NGCC plants have more opportunities to displace coal-fired generators. In contrast, when coal prices are much lower than in the Reference case, or natural gas prices are much higher, the ratio is higher, indicating less likelihood of dispatch-level competition between coal and natural gas. In both the High Oil and Gas Resource case and the High Coal Cost case, the average NGCC plant is close to parity with, or more economical than, the average coal-fired steam turbine.

Capacity by plant type

In all five cases, coal-fired generating capacity in 2025 (Figure 28) is below the 2011 total and remains lower through 2040 (Figure 29), as retirements outpace new additions of coal-fired capacity. Coal and natural gas prices are key factors in the decision to retire a power plant, along with environmental regulations and the demand for electricity. In the Low Oil and Gas Resource case and Low Coal Cost case, there are slightly fewer retirements than in the Reference case, as a higher fuel cost ratio for power generation is more favorable to coal-fired power plants. In the High Oil and Gas Resource case and High Coal Cost case, coal-fired plants are used less, and more coal-fired capacity is retired than in the Reference case. In the Reference case, 49 gigawatts of coal-fired capacity is retired from 2011 to 2040, compared with a range from 38 gigawatts to 73 gigawatts in the alternative cases. The interaction of fuel prices and environmental rules is a key factor in coal plant retirements. *AEO2013* assumes that all coal-fired plants have flue gas desulfurization equipment (scrubbers) or dry sorbent injection systems installed by 2016 to comply with the Mercury and Air Toxics Standards. Higher coal prices, lower wholesale electricity prices (often tied to natural gas prices), and reduced use may make investment in such equipment uneconomical in some cases, resulting in plant retirements.

In all the cases examined, new additions of coal-fired capacity from 2012 to 2040 total less than 15 gigawatts. For new builds, natural gas and renewables generally are more competitive than coal, and concerns surrounding potential future GHG legislation also dampen interest in new coal-fired capacity [*82*]. New capacity additions are not the most important factor in the competition between coal and natural gas for electricity generation. There is also significant dispatch-level competition in determining how intensively to operate existing coal-fired power plants versus new and existing natural gas-fired plants.

New natural gas-fired capacity, including combined-cycle units and combustion turbines, comprises the majority of new additions in the Reference case. The total capacity of all U.S. natural gas-fired power plants grows in each of the cases, but the levels vary depending on the relative fuel prices projected. Across the resource cases, NGCC capacity in 2025 ranges between 227 and 243 gigawatts, and in 2040 it ranges between 262 and 344 gigawatts, reflecting the impacts of fuel prices on the operating costs of new capacity.

Figure 27. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in five cases, 2008-2040

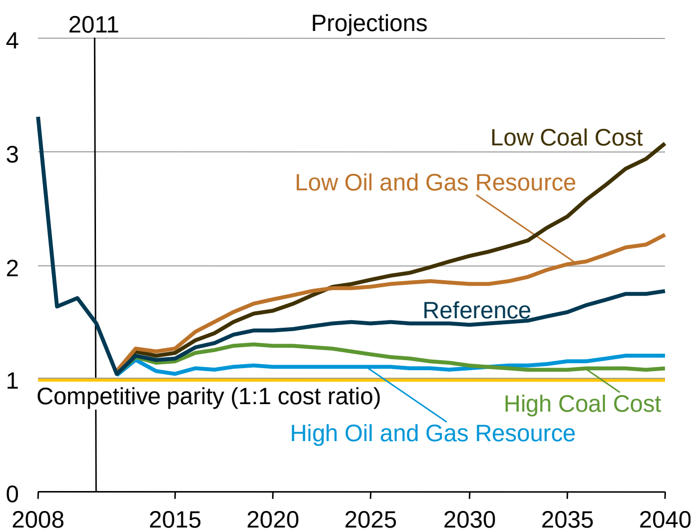


Figure 28. Power sector electricity generation capacity by fuel in five cases, 2011 and 2025 (gigawatts)

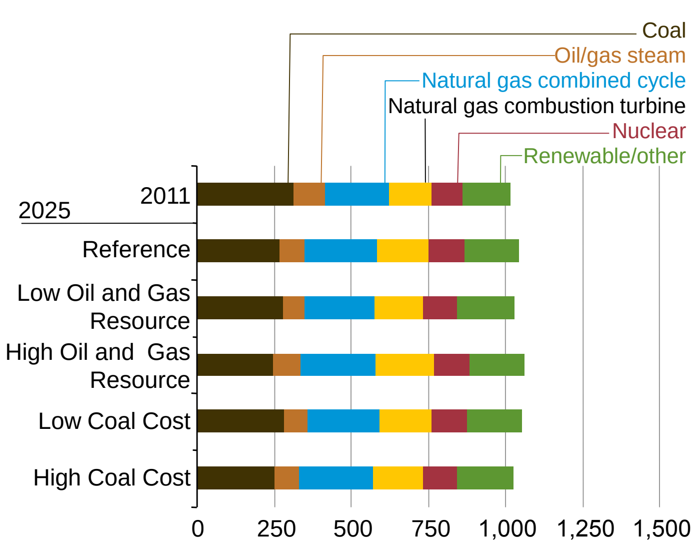
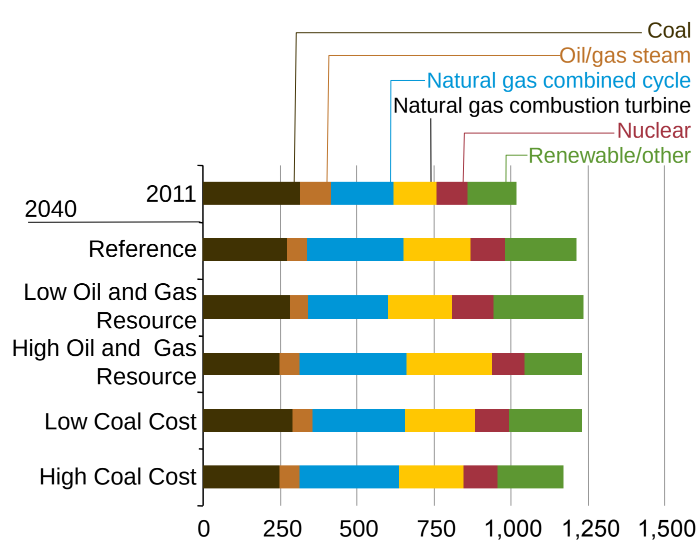


Figure 29. Power sector electricity generation capacity by fuel in five cases, 2011 and 2040 (gigawatts)



New nuclear capacity and renewable capacity are affected primarily by changes in natural gas prices, with substantial growth in both technologies occurring in the Low Oil and Gas Resource case. Most of the increase occurs after 2025, when delivered natural gas prices in that case exceed $7 per million Btu, and the costs of the nuclear and renewable technologies have fallen from current levels. In this case, higher natural gas prices reduce the competitiveness of natural gas as a fuel for new capacity builds, leading to higher prices and lower demand for electricity. Total generating capacity is similar in the Reference case and the Low Oil and Gas Resource case, but the large amount of renewable capacity built in the Low Oil and Gas Resource case—particularly wind and solar—does not contribute as much generation as NGCC capacity toward meeting either electricity demand or reserve margin requirements.

Generation by fuel

In the Reference case, coal-fired generation increases by an average of 0.2 percent per year from 2011 through 2040. Even though less capacity is available in 2040 than in 2011, the average capacity utilization of coal-fired generators increases over time. In recent years, as natural gas prices have fallen and natural gas-fired generators have displaced coal in the dispatch order, the average capacity factor for coal-fired plants has declined substantially. The coal fleet maintained an average annual capacity factor above 70 percent from 2002 through 2008, but the capacity factor has declined since then, falling to about 57 percent in 2012. As natural gas prices increase in the *AEO2013* Reference case, the utilization rate of coal-fired generators returns to previous historical levels and continues to rise, to an average of around 74 percent in 2025 and 78 percent in 2040. Across the alternative cases, coal-fired generation varies slightly in 2025 (Figure 30) and 2040 (Figure 31) as a result of differences in plant retirements and slight differences in utilization rates. The capacity factor for coal-fired power plants in 2040 ranges from 69 percent in the High Oil and Gas Resource case to 81 percent in the Low Oil and Gas Resource case.

Natural gas-fired generation varies more widely across the alternative cases, as a result of changes in the utilization of NGCC capacity, as well as the overall amount of combined-cycle capacity available. In recent years, the utilization rate for NGCC plants has increased, while the utilization rate for coal-fired steam turbines has declined. Capacity factors for the two technologies were about equal at approximately 57 percent in 2012. As natural gas prices rise in the Reference case, the average capacity factor for combined-cycle plants drops below 50 percent in the near term and remains between 48 percent and 54 percent over the remainder of projection period. In the High Oil and Gas Resource case, where combined-cycle generation is more competitive with existing coal-fired generation and the largest amount of new combined-cycle capacity is added, the average capacity factor for combined-cycle plants rises to 70 percent in the middle years of the projection period and remains about 63 percent through the remainder of the projection period. In the Low Oil and Gas Resource case, generation from combined-cycle plants is 37 percent lower in 2040 than in the Reference case, and the capacity factor for NGCC plants declines from around 45 percent in the mid term to 36 percent in 2040. Natural gas-fired generation in the Low Oil and Gas Resource case is replaced primarily with generation from new nuclear and renewable power plants. Similar fluctuations in natural gas-fired generation, but smaller in magnitude, are also seen across the coal cost cases.

The coal and natural gas shares of total electricity generation vary widely across the alternative cases. The coal share of total generation varies from 30 percent to 43 percent in 2025 and from 28 percent to 40 percent in 2040. The natural gas share varies from 22 percent to 36 percent in 2025 and from 18 percent to 42 percent in 2040. In the High Oil and Gas Resource case, natural gas becomes the dominant generation fuel after 2015, and its share of total generation is 42 percent in 2040 (Figure 32).

Figure 30. Power sector electricity generation by fuel in five cases, 2011 and 2025 (billion kilowatthours)

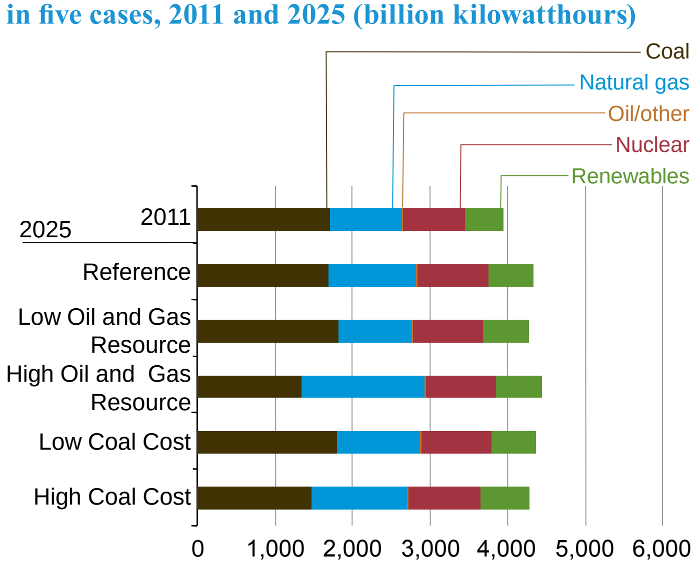
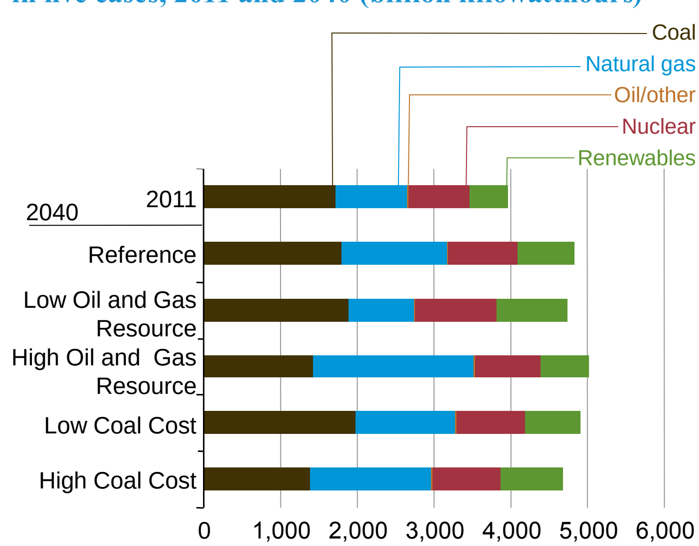


Figure 31. Power sector electricity generation by fuel in five cases, 2011 and 2040 (billion kilowatthours)



Regional impacts

Competition in the southeastern United States

While examining the national-level results is useful, the competition between coal and natural gas is best examined in a region that has significant amounts of both coal-fired and natural gas-fired capacity, such as the southeastern United States. In the southeastern subregion of the SERC Reliability Corporation (EMM Region 14), the ratio of average fuel costs for NGCC plants to average fuel costs for coal-fired steam turbines in both the High Coal Cost case and the High Oil and Gas Resource case is below that in the Reference case (Figure 33). In this region, which has a particularly efficient fleet of NGCC plants, the fuel cost ratios in both the High Coal Cost case and the High Oil and Gas Resource case remain near or below competitive parity for the majority of the projection period, indicating continued strong competition in the region. While average coal steam turbine heat rates remain largely static over the projection period, the average NGCC heat rates in this region drop appreciably by 2040, and are among the lowest in the nation.

The delivered cost of coal in the region is somewhat higher than in many other regions. Central Appalachian and Illinois Basin coals must be transported by rail or barge to the Southeast, and coal from the Powder River Basin must travel great distances by rail. The region also uses some imported coal, typically along the Gulf Coast, which tends to be more expensive.

In the High Oil and Gas Resource case, retirements of coal-fired generators in this region total 8 gigawatts in 2016 (5 gigawatts higher than in the Reference case) and remain at that level through 2040. Lower fuel prices for new natural gas-fired capacity, along with requirements to install environmental control equipment on existing coal-fired capacity, leads to additional retirements of coal-fired plants. As a result, the coal share of total capacity in the region drops from 39 percent in 2011 to 23 percent in 2040 in the High Oil and Gas Resource case, and the NGCC share rises from 24 percent in 2011 to 40 percent in 2040, when it accounts for the largest share of total generating capacity.

The capacity factors of coal-fired and NGCC power plants also vary across the cases, resulting in a significant shift in the shares of generation by fuel. The natural gas share of total electric power generation in the SERC southeast subregion grows from 31 percent in 2011 to 36 percent in 2040 in the Reference case, as compared with 56 percent in 2040 in the High Oil and Gas Resource case. Conversely, the coal share drops from 47 percent in 2011 to 40 percent in 2040 in the Reference case, compared with 20 percent in 2040 in the High Oil and Gas Resource case.

Competition in the Midwest

In the western portion of the Reliability*First* Corporation (RFC) region (EMM Region 11), which covers Ohio, Indiana, and West Virginia as well as portions of neighboring states, the ratio of the average fuel cost for natural gas-fired combined-cycle plants to the average fuel cost for coal-fired steam turbines approaches parity in the High Coal Cost case and the High Oil and Gas Resource case (Figure 34). The RFC west subregion is more heavily dependent on coal, with coal-fired capacity accounting for 58 percent of the total in 2011. The coal share of total capacity falls to 48 percent in 2040 in the Reference case with the retirement of nearly 15 gigawatts of coal-fired capacity from 2011 to 2017. NGCC capacity, which represented only 7 percent of the region's total generating capacity in 2011, accounts for 11 percent of the total in 2040 in the Reference case.

Figure 32. Power sector electricity generation from coal and natural gas in two cases, 2008-2040 (billion kilowatthours)

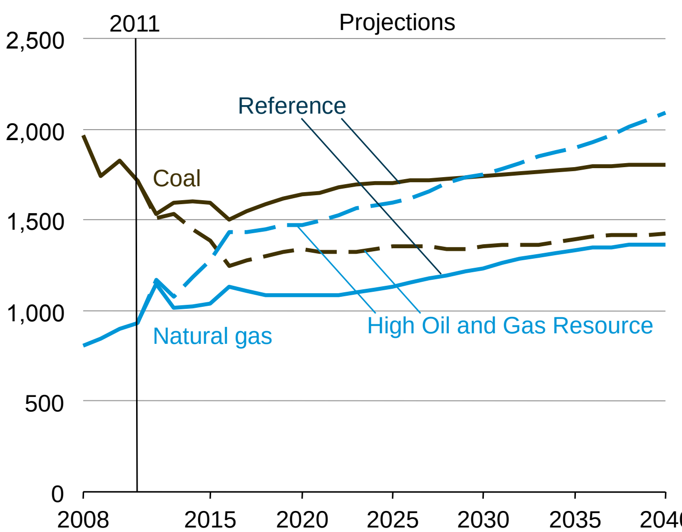
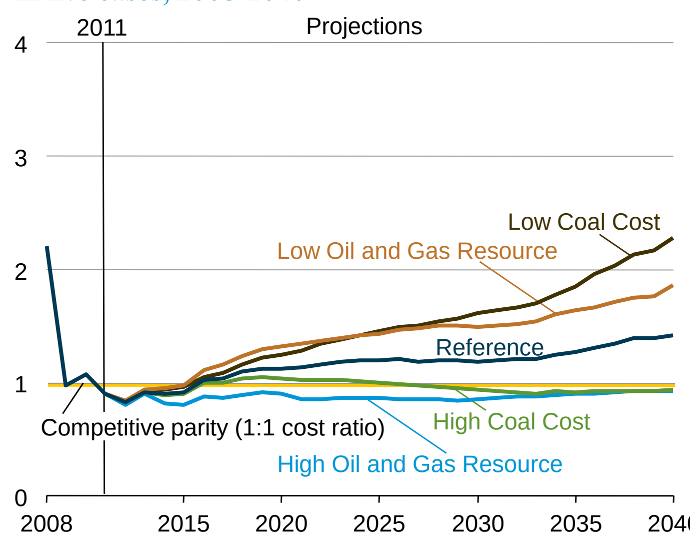


Figure 33. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in the SERC southeast subregion in five cases, 2008-2040



In the High Coal Cost case, only a limited amount of shifting from coal to natural gas occurs in this region, which has a large amount of existing coal-fired capacity and access to multiple sources of coal, including western basins as well as the Illinois and Appalachian basins. Higher transportation rates in this case deter the use of Western coal in favor of more locally sourced Interior and Appalachian coal. The ability to switch coal sources to moderate fuel expenditures reduces the economic incentive to build new NGCC plants, even with coal prices that are higher than those in the Reference case. The NGCC share of the region's total capacity does increase in the High Oil and Gas Resource case relative to the Reference case, to 16 percent in 2040. In all the cases, however, coal-fired generating capacity makes up more than 42 percent of the total in 2040.

The different capacity factors of coal-fired steam turbines and NGCC capacity contribute to a shift in the generation fuel shares, but the lower levels of natural gas-fired capacity in the region limit the impacts relative to those seen in the Southeast. The natural gas share of total generation in the region grows from 6 percent in 2011 to 8 percent in 2040 in the Reference case, 10 percent in 2040 in the High Coal Cost case, and 18 percent in 2040 the High Oil and Gas Resource case. Coal's share of the region's electric power sector generation declines from 66 percent in 2011 to 64 percent in 2040 in the Reference case, and to 54 percent in both the High Coal Cost case and the High Oil and Gas Resource case. In the High Coal Cost case, much of the coal-fired generation is replaced with biomass co-firing rather than natural gas, because without the lower natural gas prices in the High Oil and Gas Resource case, it is more economical to use biomass in existing coal-fired units than to build and operate new natural gas-fired generators.

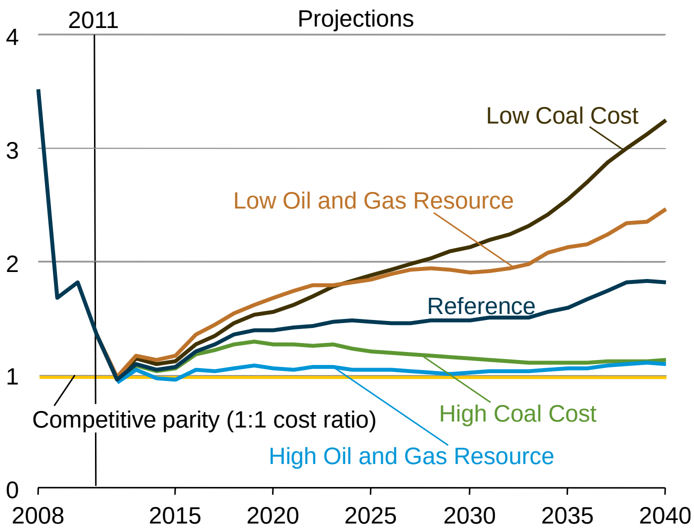
Other factors affecting competition

In addition to relative fuel prices, a number of factors influence the competition between coal-fired steam turbines and natural gas-fired combined-cycle units. One factor in the dispatch-level competition is the availability of capacity of each type. In New England, for example, competition between coal and natural gas is not discussed, because very little coal-fired capacity exists or is projected to be built in that region, even in the *AEO2013* alternative fuel price cases. New England is located far from coal sources, and a regional cap on GHG emissions is in place, which makes investment in new coal-fired capacity unlikely. In the southeastern United States, however, there is more balance between natural gas-fired and coal-fired generating resources.

Further limitations not discussed above include:

- Start-up and shutdown costs. In general, combined-cycle units are considered to be more flexible than steam turbines. They can ramp their output up and down more easily, and their start-up and shutdown procedures involve less time and expense. However, plants that are operated more flexibly (i.e., ramping up and down and cycling on and off) often have higher maintenance requirements and higher maintenance costs.
- Emission rates and allowance costs. Another component of operating costs not mentioned above is the cost of buying emissions allowances for plants covered by the Acid Rain Program and Clean Air Interstate Rule. In recent years, allowance prices have dropped to levels that make them essentially negligible, although for many years they were a significant component of operating costs.
- Transmission constraints on the electricity grid and other reliability requirements. Certain plants, often referred to as reliability must-run plants, are located in geographic areas where they are required to operate whenever they are available. In other cases, transmission limitations on the grid at any given time may determine maximum output levels for some plants.

Figure 34. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in the RFC west subregion in five cases, 2008-2040



5. Nuclear power in *AEO2013*

In 2011, approximately 19 percent of the nation's electricity was generated by 104 operating commercial nuclear reactors, totaling 101 gigawatts of capacity. In the *AEO2013* Reference case, annual generation from nuclear power grows by 14.3 percent from the 2011 total to 903 gigawatthours in 2040. However, the nuclear share of the overall generation mix declines to 17 percent as growth in nuclear generation is outpaced by the increases in generation from natural gas and renewables. The Reference case projects the addition of 19 gigawatts of nuclear capacity from 2011 to 2040, in comparison with the addition of 215 gigawatts of natural gas capacity and 104 gigawatts of renewable capacity.

Nuclear capacity is added both through power uprates at existing nuclear power plants and through new builds. Uprates at existing plants account for 8.0 gigawatts of nuclear capacity additions in the Reference case and new construction adds 11.0 gigawatts of capacity over the projection period. About 5.5 gigawatts of new capacity results from Watts Bar Unit 2, Summer Units 2 and 3, and Vogtle Units 3 and 4, all of which are projected to be online by 2020. The *AEO2013* Reference case includes the retirement of 0.6 gigawatts at Oyster Creek in 2019, as well as retirements of an additional 6.5 gigawatts of capacity toward the end of the projection. *AEO2013* also includes several alternative cases that examine the impacts of different assumptions about the long-term operation of existing nuclear power plants, new builds, deployment of new technologies, and the impacts on electricity markets of different assumptions about future nuclear capacity.

Uprates

Power uprates increase the licensed capacity of existing nuclear power plants and enable those plants to generate more electricity [*83*]. The U.S. Nuclear Regulatory Commission (NRC) must approve all uprate projects before they are undertaken and verify that the reactors will still be able to operate safely at the proposed higher levels of output. Power uprates can increase plant capacity by up to 20 percent of the original licensed capacity, depending on the magnitude and type of uprate project. Capital expenditures may be small (e.g., installing a more accurate sensor) or significant (e.g., replacing key plant components, such as turbines).

EIA relied on both reported data and estimates to define the uprates included in *AEO2013*. Reported data comes from the Form EIA-860 [*84*], which requires all nuclear power plant owners to report plans to build new plants or make modifications (such as an uprate) to existing plants within the next 10 years. In 2011, nuclear power plants reported plans to complete a total of 1.5 gigawatts of uprate projects over the next 10 years.

In addition to the reported uprates, EIA included an additional 6.5 gigawatts of uprates over the projection period. The inclusion of potential uprate capacity is based on interactions with EIA stakeholders who have significant experience in implementing power plant uprates.

New Builds

Building a new nuclear power plant is a complex operation that can take more than a decade to complete. Projects generally require specialized high-wage workers, expensive materials and components, and engineering construction expertise, which can be provided by only a select group of firms worldwide. In the current economic environment of low natural gas prices and flat demand for electricity, the overall market conditions for new nuclear plants are challenging.

Nuclear power plants are among the most expensive options for new electric generating capacity [*85*]. The *AEO2013* Reference case assumes that the overnight capital costs (the cost before interest) associated with building a nuclear power plant in 2012 were $5,429 (2011 dollars) per kilowatt, which translates to almost $12 billion for a dual-unit 2,200-megawatt power plant. The estimate does not include such additional costs as financing, interest carried forward, and peripheral infrastructure updates [*86*]. Despite its cost, deployment of new nuclear capacity supports the long-term resource plans of many utilities by allowing fuel diversification and by providing a hedge against potential future GHG regulations or higher natural gas prices.

Incentive programs encourage the construction of new reactors in the United States. At the federal level, the Energy Policy Act of 2005 (EPACT2005) established a Loan Guarantee Program for new nuclear plants that are completed and operational by 2020 [*87*]. A total of $18.5 billion is available, of which $8.3 billion has been conditionally committed to the construction of Southern Company's Vogtle Units 3 and 4 [*88*]. EPACT2005 also provided a PTC of $18 per megawatt hour for electricity produced during the first 8 years of plant operation [*89*]. To be eligible for this credit, new nuclear plants must be operational by 2021, and the credit is limited to the first 6 gigawatts of new nuclear capacity. In addition to federal incentives, several states provide a favorable regulatory environment for new nuclear plants by allowing plant owners to recover their investments through retail electricity rates.

In addition to reported plans to build new nuclear power plants, another 5.5 gigawatts of unplanned capacity is built in the later years of the Reference case projection. Higher natural gas prices, growth in electricity demand, and the need to displace retired nuclear and coal-fired capacity all play a role in the growth at the end of the projection period in the Reference case.

Retirements

NRC has the authority to issue initial operating licenses for commercial nuclear power plants for a period of 40 years. Decisions to apply for operating license renewals are made entirely by nuclear power plant owners, and typically they are based on economics and the ability to meet NRC requirements.

In April 2012, Oyster Creek Unit 1 became the first commercial nuclear reactor to have operated for 40 years, followed by Nine Mile Point Unit 1 in August, R. E. Ginna in September, and Dresden Unit 2 in December 2012. Two additional plants, H.B. Robinson Unit 2 and Point Beach Unit 1, will complete 40 years of operation in 2013. As of December 2012, the NRC had granted license renewals to 72 of the 104 operating U.S. reactors, allowing them to operate for a total of 60 years. Currently, the NRC is reviewing license renewal applications for 13 reactors, and 15 more applications for license renewals are expected between 2013 and 2019.

NRC regulations do not limit the number of license renewals a nuclear power plant may be granted. The nuclear power industry is preparing applications for license renewals that would allow continued operation beyond 60 years. The first such application, for permission to operate a commercial reactor for a total of 80 years is tentatively scheduled to be submitted in 2015. Aging plants may face a variety of issues that could lead to a decision not to apply for a second license renewal, including both economic and regulatory issues—such as increased operation and maintenance (O&M) costs and capital expenditures to meet NRC requirements. Industry research is focused on identifying challenges that aging facilities might encounter and formulating potential approaches to meet those challenges [*90*, *91*]. Typical challenges involve degradation of structural materials, maintaining safety margins, and assessing the structural integrity of concrete [*92*].

The outcome of pending research and market developments will be important to future decisions regarding life extensions beyond 60 years. The *AEO2013* Reference case assumes that the operating lives of most of the existing U.S. nuclear power plants will be extended at least through 2040. The only planned retirement included in the Reference case is the announced early retirement of the Oyster Creek nuclear power station in 2019, as reported on Form EIA-860. The Reference case also assumes an additional 7.1 gigawatts of nuclear power capacity retirements by 2040, representing about 7 percent of the current fleet. These generic retirements reflect uncertainty related to issues associated with long-term operations and age management.

In March 2012, the NRC issued three orders [*93*] that require nuclear power plants to implement requirements related to lessons learned from the accident at Japan's Fukushima Daiichi nuclear power plant in March 2011. Compliance assessments are underway currently at U.S. nuclear power plants. The requirements of the orders must be implemented by December 2016 and will remain in place until they are superseded by rulemaking. Given the evolving nature of NRC's regulatory response to the accident at Fukushima Daiichi, the Reference case does not include any retirements that could result from new NRC requirements that may involve plant modifications to meet such requirements.

Small Modular Reactors

Small Modular Reactor (SMR) technology differs from traditional, large-scale light-water reactor technology in both reactor size and plant scalability. SMRs are typically smaller than 300 megawatts and can be built in modular arrangements. Traditional reactors are generally 1,000 megawatts or larger. The initial estimates for scalable SMRs range from 45 to 225 megawatts. SMRs are small enough to be fabricated in factories and can be shipped to sites via barge, rail, or truck. Those factors may reduce both capital costs and construction times. Smaller SMRs offer utilities the flexibility to scale nuclear power production as demand changes.

The actual construction of a large nuclear power plant can take up to a decade. During construction, the plant owner may incur significant interest costs and risk further cost increases because of delays and cost overruns. SMRs have the potential to mitigate some of the risks, based on their projected construction period of 3 years. Moody's credit rating agency has described large nuclear power plants as bet-the-farm endeavors for most companies, given the size of the investment and length of time needed to build a nuclear power facility [*94*], as highlighted by comparisons of the costs of building nuclear power plants with the overall sizes of the companies building them. *AEO2013* assumes that the overnight cost of a 2,200-megawatt nuclear power plant is approximately $12 billion, which is a significant share of the market capitalization of some of the nation's largest electric power companies. For example, the largest publicly traded company that owns nuclear power plants in the United States has a market capitalization of about $50 billion [*95*].

Although SMRs may offer several potential advantages, there are key issues that remain to be resolved. SMRs are not yet licensed by the NRC. While there are many similarities between SMRs and traditional large reactors, there are several key differences identified by the NRC that will need to be reviewed before a design certification is issued. Until the situation is clarified, there will be substantial uncertainty about the final costs of SMRs. In addition, the NRC must develop a regulatory infrastructure to support licensing review of the SMR designs. The NRC has identified several potential policy and technical issues associated with SMR licensing [*96*]. In August 2012, the NRC provided a report to Congress that addressed the licensing of reactors, including SMRs [*97*, *98*].

Ultimately, the path to commercialization for SMRs is to develop the infrastructure to manufacture the modules in factories and then ship the completed units to plant sites. Performing a majority of the construction in factories could standardize the assembly process and result in cost savings, as has occurred with U.S. Navy shipbuilding, where construction cost savings have been achieved by centralizing much of the production in a controlled factory setting [*99*].

In March 2012, DOE announced its intention to provide $450 million in funding to assist in the initial development of SMR technology [*100*]. Through cost-sharing agreements with private industry, DOE solicited proposals for promising SMR projects that have the potential to be licensed by the NRC and achieve commercial operation by 2022. In November 2012, DOE announced the selection of Babcock & Wilcox [*101*], in partnership with the Tennessee Valley Authority (TVA) and Bechtel International, to share the costs of preparing a license application for up to four SMRs at TVA's Clinch River site in Oak Ridge, Tennessee.

Alternative nuclear cases

In the *AEO2013* Low Nuclear case, uprates currently under review by, or expected to be submitted to, the NRC are not included unless they have been reported to EIA. No nuclear power plants are assumed to receive second license renewals in the Low Nuclear case; all plants are assumed to retire after roughly 60 years of operation, except for those specifically discussed below. Other than the 5.5 gigawatts of new capacity already planned, no new nuclear power plants are assumed to be built.

In addition to the retirement of Oyster Creek in 2019, the Low Nuclear case includes the retirement of Kewaunee in 2013. Nuclear power plants that are in long-term shutdown also are assumed to be retired, including San Onofre Nuclear Generating Station (SONGS) Unit 3 and Crystal River Unit 3. Both plants have been in extended shutdown for more than a year, and there is substantial uncertainty about the cost and feasibility of operating the facilities in the future. Southern California Edison is assessing the long-term viability of SONGS Unit 3 and has indicated that it will not be operating for some time, in light of ongoing steam generator issues [*102*, *103*, *104*]. Crystal River Unit 3 has been offline since September 2009, as a result of cracks in the containment structure. As of October 2012, replacement power costs and the repairs to Unit 3 were initially estimated to be between $1.3 and $3.5 billion. However, repairs could eventually include replacement of the entire containment structure. Further repairs to Crystal River Unit 3 are being evaluated [*105*, *106*]. In the Reference and High Nuclear cases, SONGS Unit 3 and Crystal River Unit 3 are assumed to return to service when maintenance and repairs have been completed.

The High Nuclear case assumes that all existing nuclear power plants receive their second license renewals and operate through 2040. Uprates in the High Nuclear case are consistent with those in the Reference case (8.0 gigawatts added by 2025). In addition to plants already under construction, the High Nuclear case assumes that nuclear power plants with active license applications at the NRC are constructed, provided that they have a tentatively scheduled Atomic Safety and Licensing Board hearing and will deploy a certified Nuclear Steam Supply System design. This assumption results in the planned addition of 13.3 gigawatts of new nuclear capacity, which is 7.8 gigawatts above what is assumed in the Reference case.

In the High Nuclear case, planned capacity additions are more than double those in the Reference case, but unplanned additions do not change noticeably. The additional planned capacity reduces the need for new unplanned capacity. The importance of natural gas prices for nuclear power plant construction is highlighted in the results of the Low Oil and Gas Resource case, where the average price of natural gas delivered to the electric power sector in 2040 is 26 percent higher than in the Reference case. The higher natural gas prices make nuclear power a more competitive source for new generating capacity, resulting in the addition of 26 gigawatts of unplanned nuclear power capacity from 2011 to 2040. In the High Oil and Gas Resource case, where the average price of natural gas delivered to the electric power sector in 2040 is 39 percent lower than in the Reference case, no unplanned nuclear capacity is built. Similarly, no unplanned nuclear capacity is added in the Low Nuclear case (Figure 35).

The Small Modular Reactor case assumes that SMRs will be the nuclear technology choice available after 2025, rather than traditional gigawatt-scale nuclear power plants. There is uncertainty surrounding SMR design certification and supply chain and infrastructure development, which makes it difficult to develop capital cost assumptions for SMRs. The Small Modular Reactor case assumes that SMRs have the same overnight capital costs per kilowatt as a traditional 1,100-megawatt unit, consistent with cost assumptions in the Reference case. This assumption was made for the purpose of assessing the impact on the amount of new nuclear capacity of a shorter construction period for SMRs than for traditional nuclear power plants.

In the High Nuclear case, nuclear generation in 2040 is 12 percent higher than in the Reference case, and the nuclear share of total generation is 19 percent, compared with 17 percent in the Reference case. The increase in nuclear generation offsets a decline in generation from natural gas (Figure 36) and renewable fuels, which are 5 percent and 2 percent lower in 2040, respectively, than in the Reference case. Coal-fired generation in the High Nuclear case is virtually the same as in the Reference case.

In the Low Nuclear case, generation from nuclear power in 2040 is 44 percent lower than in the Reference case, due to the loss of 45.4 gigawatts of nuclear capacity that is retired after 60 years of operation. As a result, the nuclear share of total generation falls to 10 percent in 2040. The loss of generation is made up primarily by increased generation from natural gas, which is 17 percent higher in the Low Nuclear case than in the Reference case in 2040. Generation from coal and generation from renewables in 2040 both are 2 percent higher than projected in the Reference case.

CO_2 emissions from the electric power sector are affected by the share of nuclear power in the generation mix. Unlike coal- and natural gas-fired plants, nuclear power plants do not emit CO_2. Consequently, CO_2 emissions from the electric power sector in 2040 are 5 percent lower in the Reference case than in the Low Nuclear case, as a result of switching from nuclear generation to

Figure 35. Nuclear capacity additions in five cases, 2011-2040 (gigawatts)

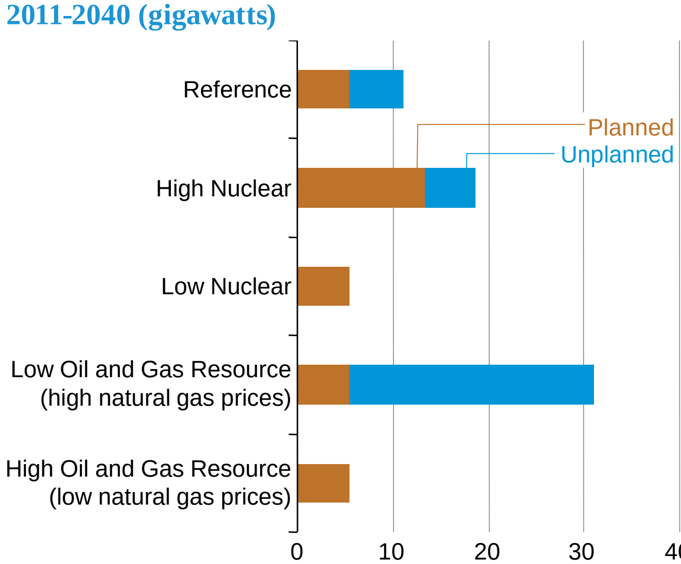
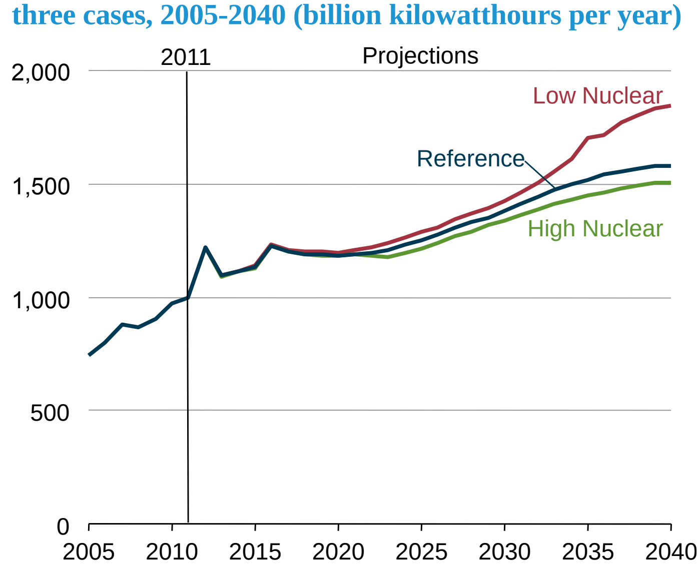


Figure 36. Electricity generation from natural gas in three cases, 2005-2040 (billion kilowatthours per year)



mostly natural gas and some coal [107]. In the High Nuclear case, CO_2 emissions from the power sector are 1 percent lower than projected in the Reference case, because the High Nuclear case results in slightly more generation from nuclear units than from fossil-fueled units (Figure 37).

Real average electricity prices in 2040 are 1 percent lower in the High Nuclear case than in the Reference case, as slightly less natural gas capacity is dispatched, reducing natural gas prices, which lowers the marginal price of electricity. In the Low Nuclear case, average electricity prices in 2040 are 5 percent higher than in the Reference case as a result of the retirement of a significant amount of nuclear capacity, which has relatively low operating costs, and its replacement with natural gas capacity, which has higher fuel costs that are passed through to consumers in retail electricity prices.

The impacts of nuclear plant retirements on retail electricity prices in the Low Nuclear case are more apparent in regions with relatively large amounts of nuclear capacity. For example, electricity prices in the Low Nuclear case are 9 percent higher in 2040 than in the Reference case for the SERC (Southeast) region, 8 percent higher for the MRO (Midwest) region, and 6 percent higher in the Northeast, Mid-Atlantic, and Ohio River Valley regions [108]. Even in regions where no nuclear capacity is retired, there are small increases in electricity prices compared to the Reference case, because higher demand for natural gas in regions where nuclear plants are retired increases the price of natural gas in all regions.

In the Small Modular Reactor case, shorter construction periods result in lower interest costs, which help to reduce the overall cost of nuclear construction projects. Figure 38 compares the resulting levelized costs for traditional large reactors and for SMRs in the Reference case. For SMRs, there is a savings of approximately $6 per megawatthour in the capital portion of the levelized cost. However, estimates of the fixed O&M costs for SMRs, derived from a University of Chicago study [109], are 40 percent higher than those assumed in *AEO2013* for a new large-scale plant on a dollar per megawatt basis. The higher O&M cost could offset, in part, the capital cost benefit of a shorter construction period. Therefore, the SMR case shows only a 1.4-percent reduction in overall levelized cost relative to the Reference case. The small difference results in about 2.3 gigawatts more new nuclear power capacity in the Small Modular Reactor case than projected in the Reference case. The sensitivity to small changes in cost is notable, given the high degree of uncertainty associated with SMR costs based on the maturity of the technology.

6. Effect of natural gas liquids growth

Background

NGL include a wide range of components produced during natural gas processing and petroleum refining. As natural gas production in recent years has grown dramatically, there has been a concurrent rapid increase in NGL production. NGL include ethane, propane, normal butane (n-butane), isobutane, and pentanes plus. The rising supply of some NGL components (particularly ethane and propane) has led to challenges, in finding markets and building the infrastructure necessary to move NGL to the new domestic demand and export markets. This discussion examines recent changes in U.S. NGL markets and how they might evolve under several scenarios. The future disposition of U.S. NGL supplies, particularly in international markets, is also discussed.

Recent growth in NGL production (Figure 39) has resulted largely from strong growth in shale gas production. The lightest NGL components, ethane and propane, account for most of the growth in NGL supply between 2008 and 2012. With the exception of propane, the main source of NGL is natural gas processing associated with growing natural gas production. That growth has led to

Figure 37. Carbon dioxide emissions from electricity generation in three cases, 2005-2040 (million metric tons carbon dioxide equivalent per year)

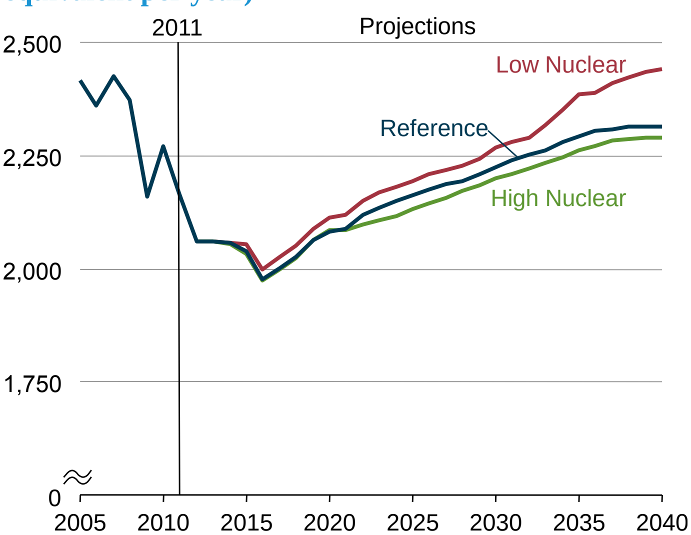
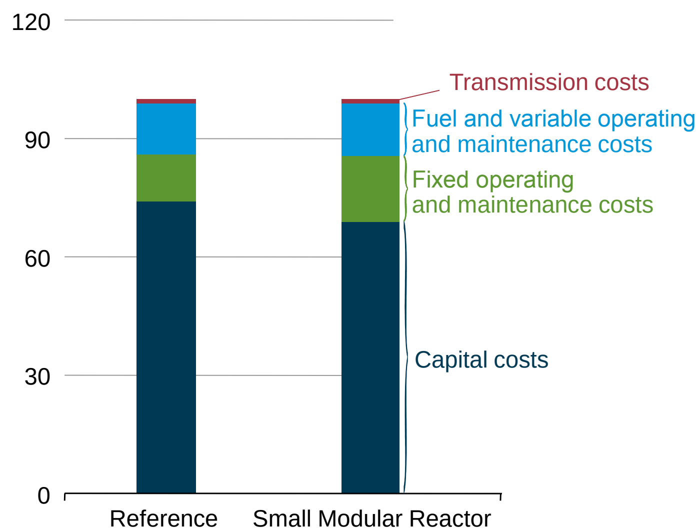


Figure 38. Levelized costs of nuclear electricity generation in two cases, 2025 (2011 dollars per megawatthour)



logistical problems in some areas. For example, much of the increased ethane supply in the Marcellus region is stranded because of the distance from petrochemical markets in the Gulf Coast area.

The uses of NGL are diverse. The lightest NGL component, ethane, is used almost exclusively as a petrochemical feedstock to produce ethylene, which in turn is a basic building block for plastics, packaging materials, and other consumer products. A limited amount of ethane can be left in the natural gas stream (ethane rejection) if the value of ethane sinks too close to the value of dry natural gas, but the amount of ethane mixed in dry natural gas is small. Propane is the most versatile NGL component, with applications ranging from residential heating, to transportation fuel for forklifts, to petrochemical feedstock for propylene and ethylene production (nearly one-half of all propane use in the United States is as petrochemical feedstock). Butanes are produced in much smaller quantities and are used mostly in refining (for gasoline blending or alkylation) or as chemical feedstock. The heaviest liquids, known as pentanes plus, are used as ethanol denaturant, blendstock for gasoline, chemical feedstock, and, more recently, as diluent for the extraction and pipeline movement of heavy crude oils from Canada.

Unlike the other NGL components, a large proportion of propane is produced in refineries (which is mixed with refinery-marketed propylene). Given that refinery production of propane and propylene has been largely unchanged since 2005 at about 540 thousand barrels per day, the growth of propane/propylene supply shown in Figure 39 is solely a result of increased propane yields from natural gas processing plants.

International demand for NGL has provided an outlet for growing domestic production, and after years of being a net importer, the United States became a net exporter of propane in 2012 (Figure 40). Although the quantities shown in Figure 40, based on EIA data, represent an aggregated mixture of propane and propylene, other sources indicate that U.S. propylene exports have been on the decline since 2007 [*110*], implying that the recent change to net exporter status is the result of increased supplies of propane from natural gas processing plants.

Current developments in NGL markets

The market currently is reacting to the growing supply of ethane and propane by expanding both domestic use of NGL and export capacity. On the domestic side, much of the U.S. petrochemical industry can absorb ethane and propane by switching from heavier petroleum-based naphtha feedstock in ethylene crackers to lighter feedstock, and recent record low NGL prices have motivated petrochemical companies to maximize the amount of ethane and propane in their feedstock slate. To take advantage of the expected growth in supplies of light NGL components resulting from shale gas production, multiple projects and expansions of petrochemical crackers have been announced (Table 7).

Although the proposed projects shown in Table 7 will largely take advantage of the growing ethane supply, a few petrochemical projects that will use propane directly as a propylene feedstock through propane dehydrogenation also have been announced [*111*]. Although expanded feedstock use is expected to be by far the largest source of expanded demand for NGL, increased use of NGL as a fuel, especially propane, also is expected—including the marketing of propane as an alternative vehicle fuel [*112*] and for agricultural use, with propane suppliers currently offering incentives for farmers to use propane as a fuel to power irrigation systems [*113*].

Notwithstanding the efforts to encourage the use of propane as a fuel in the United States, and despite current low prices, opportunities to expand the market for propane in uses other than as feedstock are limited. Therefore, producers, gas processors, and fractionators are looking for a growing export outlet for both ethane and liquefied petroleum gases (LPG—a mixture of

Figure 39. U.S. production of natural gas liquids by type, 2005-2012 (million barrels per day)

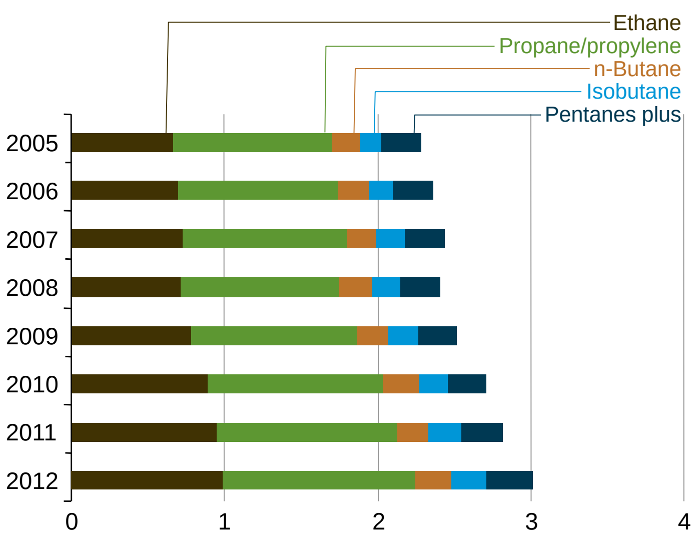
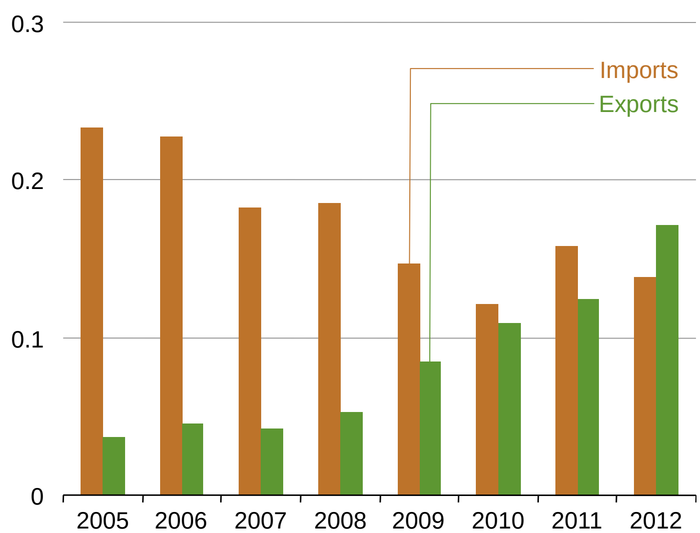


Figure 40. U.S. imports and exports of propane/propylene, 2005-2012 (million barrels per day)



propane and butane). Export capacity is being expanded, both on the U.S. Gulf Coast (Targa's expansion of both its gas processing and fractionation capability at Mont Belvieu and its export facility at Galena Park [*114*]) and on the U.S. East Coast (Sunoco Logistics' Mariner East project to supply propane and ethane to Philadelphia's Marcus Hook terminal [*115, 116*]). Exports of ethane from the Marcellus shale to chemical facilities in Sarnia, Ontario, via the Mariner West pipeline system, and from the Bakken formation to a NOVA Chemical plant near Joffre, Alberta, via the Vantage pipeline [*117*], are expected by the end of 2013. In addition to planned exports to Canada, a pipeline is being developed to transport ethane from the Marcellus to the Gulf Coast to relieve oversupply. The midstream sector's rapid buildup and expansion of natural gas processing, pipeline, and storage capacity have accommodated increasing volumes of NGL resulting from the sharp growth in shale gas production.

AEO2013 projections

AEO2013 projects continued growth in both natural gas production and NGL supplies, with NGL prices determined in large part by Brent crude oil prices and Henry Hub spot prices for natural gas (Figure 41). In the *AEO2013* Reference, Low Oil and Gas Resource, and High Oil and Gas Resource cases, industrial propane prices in 2040 range from $22.13 per million Btu (2011 dollars) in the High Oil and Gas Resource case to $27.48 per million Btu in the Low Oil and Gas Resource case, a difference of approximately 24 percent. The difference between the propane prices in the High and Low Oil and Gas Resource cases increases from $3.49 per million Btu in 2015 to $7.00 per million Btu in 2025 as natural gas prices and NGL production diverge in the two cases. Over time, however, as the divergence in NGL production narrows between the cases, the influence of oil prices on propane prices increases, and the difference in the propane prices narrows in the cases.

Production of NGPL, which are extracted from wet natural gas by gas processors, rises more steeply than natural gas production in the first half of the projection period as a result of increased natural gas and oil production from shale wells, which have relatively high liquids contents. As shale gas plays mature, NGPL production levels off or declines even as dry natural gas production increases (Figure 42).

Variations in NGL supplies and prices contribute to variations in demand for NGL. In the High Oil and Gas Resource case, propane demand in all sectors is higher than projected in the Reference case, and in the Low Oil and Gas Resource case propane demand is lower than in the Reference case. Some of the difference results from changes in the expected energy efficiency of space heating equipment in the residential sector, and possibly some fuel switching, in response to

Table 7. Proposed additions of U.S. ethylene production capacity, 2013-2020 (million metric tons per year)

Company	Location	Proposed capacity
Chevron Phillips	Baytown, TX	1.5
Exxon Mobil	Baytown, TX	1.5
Sasol	Lake Charles, LA	1.4
Dow	Freeport, TX	1.4
Shell	Beaver Co, PA	1.3
Formosa	Point Comfort, TX	0.8
Occidental/ Mexichem	Ingleside, TX	0.5
Dow	St. Charles, LA	0.4
LyondellBasell	Laporte, TX	0.4
Aither Chemicals	Kanawha, WV	0.3
Williams/Sabic JV	Geismar, LA	0.2
Ineos	Alvin, TX	0.2
Westlake	Lake Charles, LA	0.2
Williams/Sabic JV	Geismar, LA	0.1
Total		**10.1**

Figure 41. U.S. Brent crude oil and Henry Hub natural gas spot market prices in three cases, 2005-2040

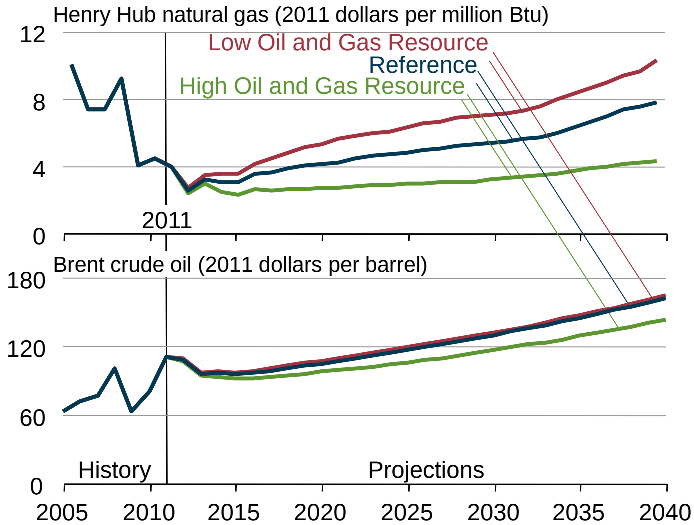
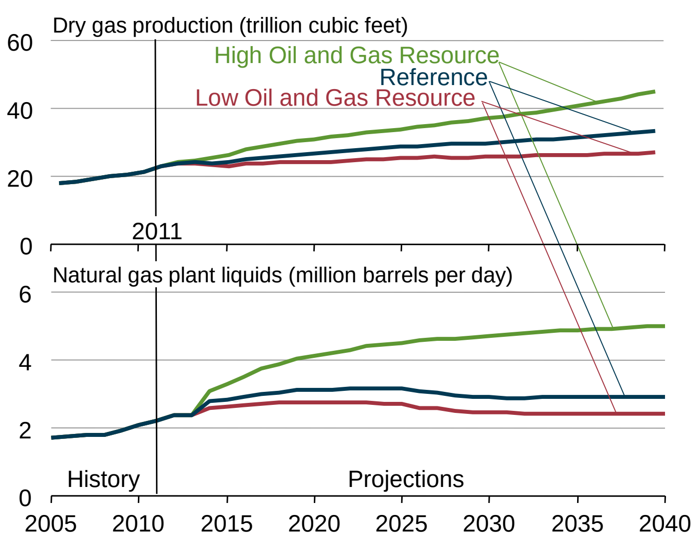


Figure 42. U.S. production of dry natural gas and natural gas plant liquids in three cases, 2005-2040



different price levels in the three cases. The remainder is attributed to variations in NGL feedstock consumption in the bulk chemicals sector, where the use of NGL as a fuel and feedstock varies with different price levels. In addition, because NGL feedstock competes with petroleum naphtha in the petrochemical industry, lower NGL prices relative to oil prices lead to more NGL consumption in the petrochemical industry.

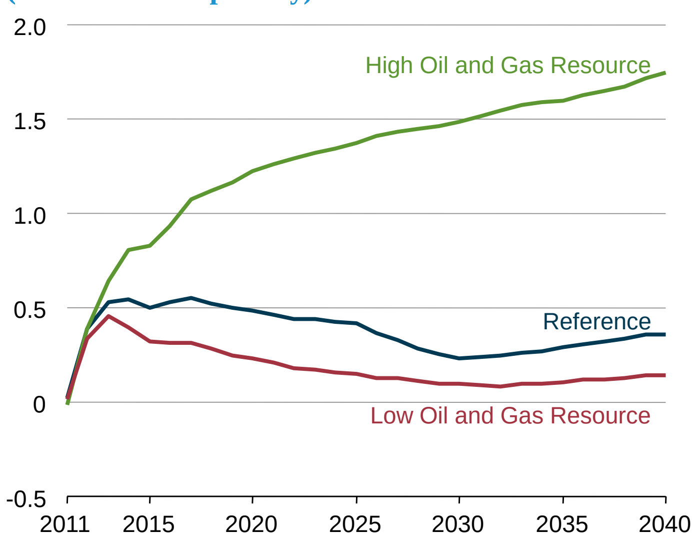
The LPG import-export balance changes rapidly when domestic supply exceeds demand. This trend continues in the near term in all three cases. In the High Oil and Gas Resource case, however, with more LPG production, net exports continue to grow throughout the projection (Figure 43). Propane accounts for most of the higher export volumes, which also include smaller amounts of butane and ethane. Currently, most U.S. exports of LPG go to Latin America, where LPG is used for heating and cooking.

International implications

The projected growth in NGL demand both for U.S. domestic uses and for export depends heavily on international markets. Current plans for ethane exports are limited to pipelines to Canada, and to date ethane is not shipped by ocean-going vessels. There is room for growth in propane exports, however, because propane is a far more versatile fuel. Propane exports to Latin America are expected to continue, along with some expansion into European markets. In addition, growing markets in Africa [*118*] for propane used in heating and cooking, along with continued demand from Asia (for fuel and feedstock), are expected to support exports of propane from both the United States and the Middle East. It remains to be seen how the market for propane exports will develop in the long term, and how the United States will seek value for its propane—converting it into chemicals for domestic use or for export, or exporting raw propane.

International markets also play a role in increased domestic consumption, particularly for expanded petrochemical feedstock consumption. The declining price of ethane improves the economics of ethylene crackers, as indicated by the planned capacities shown in Table 7. The new capacity suggests that companies are planning to gain a greater market share of ethylene demand in Asia, especially in China, which continues to be a growing importer of ethylene [*119*]. However, that economic advantage has to be weighed against the massive growth in chemical manufacturing complexes in the Middle East, as well as expansions in Asia. Feedstock availability will not be a concern in the Middle East, but most petrochemical plants in China and other Asian countries rely heavily on naphtha as a feedstock, and naphtha is produced from crude oil, which China imports. China is making efforts to diversify its feedstock slate and has announced plans to build coal-to-olefins plants [*120*]. In addition, China may develop its own shale gas resources over the next 10 to 15 years, which could provide less expensive supplies of ethane and propane. The advantage in the Middle East is its long-term access to feedstocks. Whether the United States can further capitalize on growth in basic chemical production (ethylene, propylene) to build up its higher-value chemical base, and how the production cost of those higher value chemicals would compete with those from Asia and the Middle East, is an open question.

Figure 43. U.S. net exports of liquefied petroleum gases in three cases, 2011-2040 (million barrels per day)



Future plans for U.S. propane disposition will be based on the balance between growth in domestic demand and exports. Rising exports of propane and butane raise issues as well. For example, both propane and butane can be used not only as feedstock in ethylene crackers, but also as feedstock for specific chemical product. For example, dehydrogenation processes can make propylene from propane [*121*] and butadiene from butane [*122*]. The economic value of those chemicals (which would depend on both local and global markets), weighed against the export value of the NGL inputs (propane and butane), will need to be assessed. In addition, the value of derivatives (such as polyethylene and polypropylene) will be considered from the perspective of both their export value and their production costs, which will be tied directly to the price of their precursor inputs, ethylene and propylene. Finally, U.S. refineries produce a significant amount of propylene. There is some degree of flexibility within refineries' fluid catalytic cracker units to produce propylene [*123*], and future refinery production of propylene will depend on the value of propylene itself, the value of its co-products (mostly gasoline and propane), and refining costs.

Endnotes for Issues in focus

Links current as of March 2013

65. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(a)(2)(A)(ii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
66. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(c)(3)(B)(iii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
67. Calculations based on U.S. Energy Information Administration, Form EIA-860, Schedule 3, 2011 data (Washington, DC: January 9, 2013), http://www.eia.gov/electricity/data/eia860/index.html.
68. U.S. Congress, "American Taxpayer Relief Act of 2012," P.L. 112-240, Sections 401 through 412, http://www.gpo.gov/fdsys/pkg/PLAW-112publ240/pdf/PLAW-112publ240.pdf.
69. Modeled provisions based on U.S. Congress, "American Taxpayer Relief Act of 2012," P.L. 112-240, Sections 401, 404, 405, 407, 408, 409, and 412, http://www.gpo.gov/fdsys/pkg/PLAW-112publ240/pdf/PLAW-112publ240.pdf.
70. Volatility is a measure of variability in a data series over time (more technically, the annualized standard deviation from the mean). This analysis was conducted using the GARCH estimation method for monthly average Brent crude oil prices.
71. Liquid fuels consists of crude oil and condensate to petroleum refineries, refinery gain, NGPL, biofuels, and other liquid fuels produced from non-crude oil feedstocks such as CTL and GTL.
72. Geologic characteristics relevant for hydrocarbon extraction include depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content.
73. A production type curve represents the expected production each year from a well. A well's EUR equals the cumulative production of that well over a 30-year productive life, using current technology without consideration of economic or operating conditions. A description of a production type curve is provided in the *Annual Energy Outlook 2012* "Issues in focus" article, "U.S. crude oil and natural gas resource uncertainty," http://www.eia.gov/forecasts/archive/aeo12/IF_all.cfm#uscrude.
74. A more detailed analysis of the uncertainty in offshore resources is presented in the *Annual Energy Outlook 2011* "Issues in focus" article, "Potential of offshore crude oil and natural gas resources," http://www.eia.gov/forecasts/archive/aeo11/IF_all.cfm#potentialoffshore.
75. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards: Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
76. K.A. Small and K.Van Dender, "Fuel Efficiency and Motor Vehicle Travel: The Declining Rebound Effect," University of California, Irvine, Department of Economics, Working Paper #05-06-03 (Irvine, CA: August 18, 2007), http://www.economics.uci.edu/files/economics/docs/workingpapers/2005-06/Small-03.pdf.
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78. International Maritime Organization, *Information Resources on Air Pollution and Greenhouse Gas (GHG) Emissions from International Shipping (Marpol Annex VI (SO_X, NO_X, ODS, VOC) / Greenhouse Gas (CO_2) and Climate Change)* (London, United Kingdom: December 23, 2011), http://www.imo.org/KnowledgeCentre/InformationResourcesOnCurrentTopics/AirPollutionandGreenhouseGasEmissionsfromInternationalShippping/Documents/Information%20Resources%20on%20AIR%20POLLUTION%20AND%20GHG%20EMISSIONS%20FROM%20INTERNATIONAL%20SHIPPING.pdf.
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80. U.S. Energy Information Administration, "Could the United States become the leading global producer of liquid fuels, and how much does it matter to U.S. and world energy markets?," *This Week in Petroleum* (Washington, DC: December 19, 2012), http://www.eia.gov/oog/info/twip/twiparch/2012/121219/twipprint.html.
81. The circumstances under which the United States can and cannot export crude oil under current law are more fully described in U.S. Energy Information Administration, "Market implications of increased domestic production of light sweet crude oil?," *This Week in Petroleum* (Washington, DC: November 28, 2012), http://www.eia.gov/oog/info/twip/twiparch/2012/121128/twipprint.html.

82. EPA's Proposed Carbon Pollution Standard for New Power Plants would require that new fossil fuel-fired power plants meet an output-based standard of 1,000 pounds of carbon dioxide per megawatthour of electricity generated. That standard would effectively prohibit the construction of new coal-fired power plants without carbon capture and storage. Currently, the EPA is evaluating comments and expects to issue a final rule in 2013. Because the rule is not yet final, it is not assumed to take effect in any of the *AEO2013* cases.
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Market trends

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The Reference case projection is a business-as-usual estimate, given known market, demographic, and technological trends. Most cases in the *Annual Energy Outlook 2013 (AEO2013)* generally assume that current laws and regulations are maintained throughout the projections. Such projections provide a baseline starting point that can be used to analyze policy initiatives. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, rates of technology progress, and policy changes.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

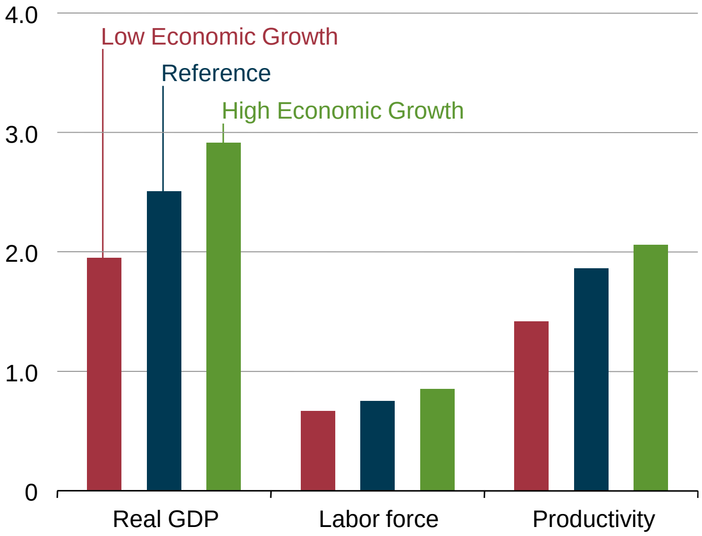
Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2013* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not as a substitute for, a complete and focused analysis of public policy initiatives.

Trends in economic activity

Productivity and investment offset slow growth in labor force

Figure 44. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2011-2040 (percent per year)



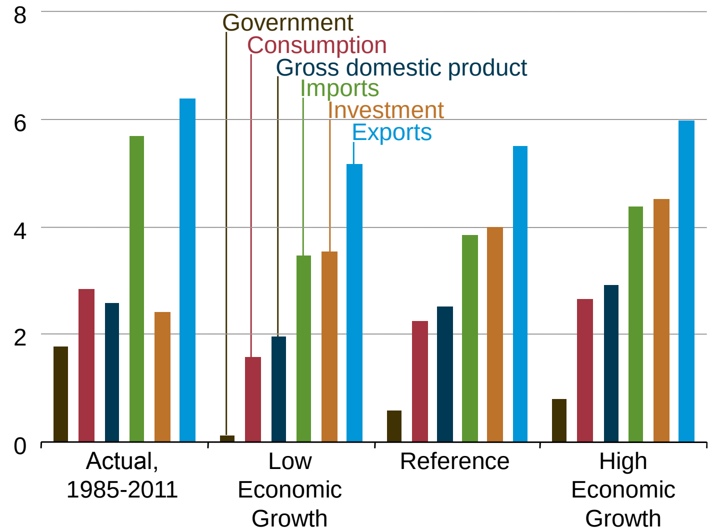
Growth in the output of the U.S. economy depends on increases in the labor force, the growth of capital stock, and improvements in productivity. In the *Annual Energy Outlook 2013 (AEO2013)* Reference case, U.S. labor force growth slows over the projection period as the baby boom generation starts to retire, but projected growth in business fixed investment and spending on research and development offsets the slowdown in labor force growth. Annual real gross domestic product (GDP) growth averages 2.5 percent per year from 2011 to 2040 in the Reference case (Figure 44), which is 0.2 percentage point slower than the growth rate over the past 30 years. Slow long-run increases in the labor force indicate more moderate long-run employment growth, with total civilian employment rising by an average of 1.0 percent per year from 2011 to 2040, from 131 million in 2011 to 174 million in 2040. The manufacturing share of total employment continues to decline over the projection period, falling from 9 percent in 2011 to 6 percent in 2040.

Real consumption growth averages 2.2 percent per year in the Reference case. The share of GDP accounted for by personal consumption expenditures varies between 66 percent and 71 percent of GDP from 2011 to 2040, with the share spent on services rising mainly as a result of increasing expenditures on health care. The share of GDP devoted to business fixed investment ranges from 10 percent to 17 percent of GDP through 2040.

Issues such as financial market reform, fiscal policies, and financial problems in Europe, among others, affect both short-run and long-run growth, adding uncertainty to the projections.

Slow consumption growth, rapid investment growth, and an increasing trade surplus

Figure 45. Average annual growth rates for real output and its major components in three cases, 2011-2040 (percent per year)



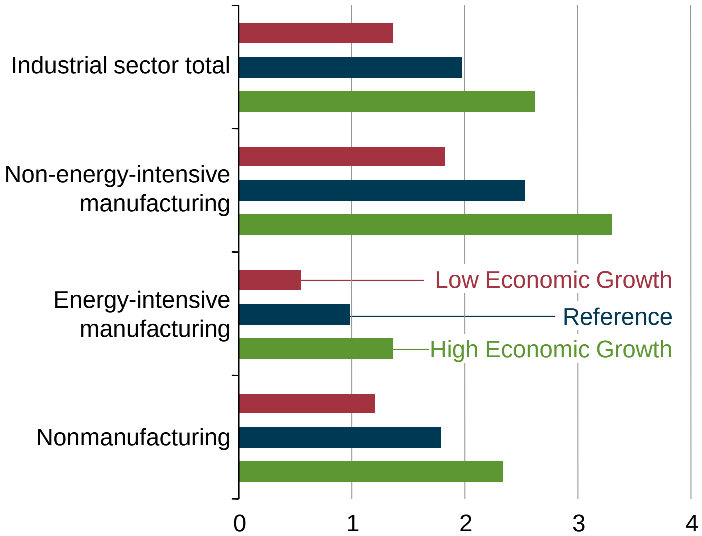
AEO2013 presents three economic growth cases: Reference, High, and Low. The High Economic Growth case assumes high growth and low inflation. The Low Economic Growth case assumes low growth and high inflation. The short-term outlook (5 years) in each case represents current thinking about economic activity in the United States and the rest of the world, about the impacts of fiscal and monetary policies, and about potential risks to economic activity. The long-term outlook includes smooth economic growth, assuming no shocks to the economy.

Differences among the Reference, High, and Low Economic Growth cases reflect different expectations for growth in population (specifically, net immigration), labor force, capital stock, and productivity, which are above trend in the High Economic Growth case and below trend in the Low Economic Growth case. The average annual growth rate for real GDP from 2011 to 2040 in the Reference case is 2.5 percent, as compared with 2.9 percent in the High Economic Growth case and 2.0 percent in the Low Economic Growth case.

Figure 45 compares the average annual growth rates for output and its major components in each of the three cases. Compared with the 1985-2011 period, investment growth from 2011 to 2040 is faster in all three cases, whereas consumption, government expenditures, imports, and exports grow more slowly in all three cases. Opportunities for trade are assumed to expand in all three cases, resulting in real trade surpluses that continue to grow throughout the projection period.

Energy-intensive industries show strong early growth in output

Figure 46. Sectoral composition of industrial shipments, annual growth rates in three cases, 2011-2040 (percent per year)



In recent decades, industrial sector shipments expanded more slowly than the overall economy, with imports meeting a large share of demand for goods and the service sector growing rapidly [*124*]. In the Reference case, real GDP grows at an average annual rate of 2.5 percent from 2011 to 2040, while the industrial sector increases by 2.0 percent per year (Figure 46).

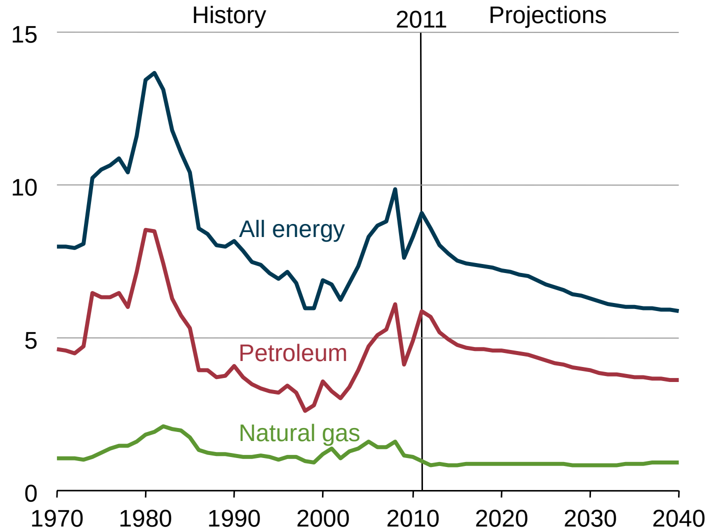
Industrial sector output goes through two distinct growth periods in the *AEO2013* Reference case, with energy-intensive industries displaying the sharpest contrast between the periods. Recovery from the recession in the U.S. industrial sector has been relatively slow, with only mining, aluminum, machinery, and transportation equipment industries recovering to 2008 levels in 2011. However, as the recovery continues and increased oil and natural gas production from shale resources begins to affect U.S. competitiveness, growth in U.S. manufacturing output accelerates through 2022.

After 2020, manufacturing output slows because of increased foreign competition and rising energy prices, which weigh most heavily on the energy-intensive industries. The energy-intensive industries grow at a rate of 1.8 percent per year from 2011 to 2020 and 0.6 percent per year from 2020 to 2040. Growth rates within the sector vary by industry, ranging from an annual average of 0.6 percent for bulk chemicals to 2.8 percent for the cement industry.

Export expansion is an important factor for industrial production growth, along with consumer demand and investment. A decline in U.S. dollar exchange rates, combined with modest escalation in unit labor costs, stimulates U.S. exports in the projection. From 2011 to 2040, real exports of goods and services increase by an average of 5.5 percent per year, while real imports of goods and services grow by an average of 3.8 percent per year.

Energy expenditures decline relative to gross domestic product and gross output

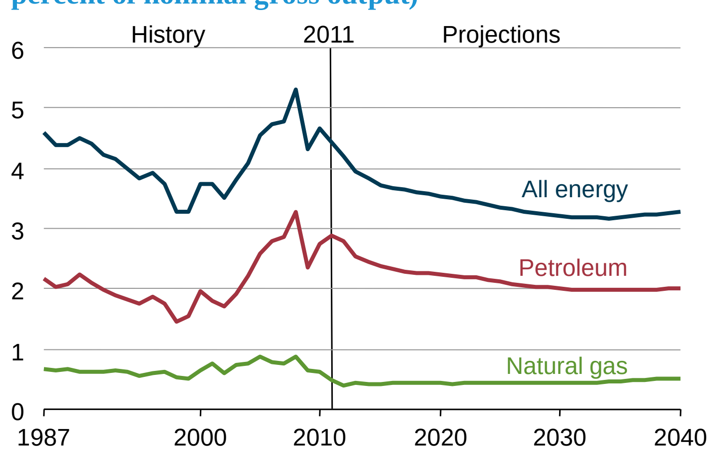
Figure 47. Energy end-use expenditures as a share of gross domestic product, 1970-2040 (nominal expenditures as percent of nominal GDP)



Total U.S. energy expenditures decline relative to GDP [*125*] in the *AEO2013* Reference case (Figure 47). The projected ratio of energy expenditures to GDP averages 6.8 percent from 2011 to 2040, which is below the historical average of 8.8 percent from 1970 to 2010.

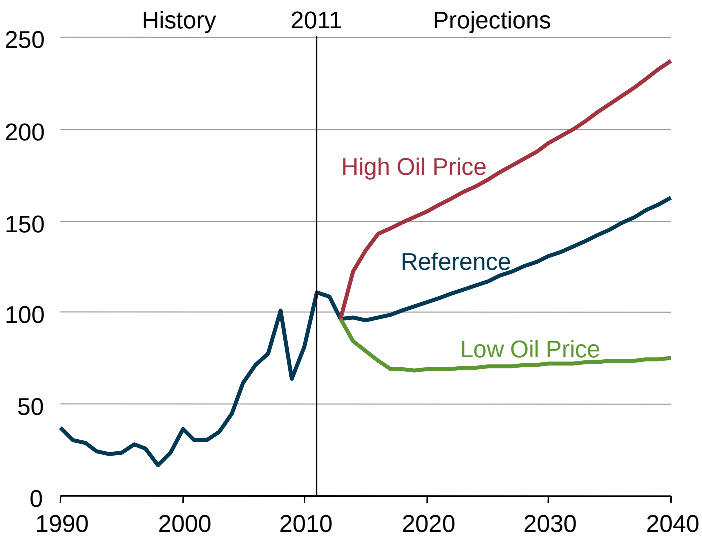
Figure 48 shows nominal energy expenditures relative to U.S. gross output, which roughly correspond to sales in the U.S. economy. Thus, the figure gives an approximation of total energy expenditures relative to total sales. Energy expenditures as a share of gross output show nearly the same pattern as their share of GDP, declining through 2040. The average shares of gross output relative to expenditures for total energy, petroleum, and natural gas, at 3.5 percent, 2.2 percent, and 0.4 percent, are close to their historical averages of 4.2 percent, 2.1 percent, and 0.7 percent, respectively.

Figure 48. Energy end-use expenditures as a share of gross output, 1987-2040 (nominal expenditures as percent of nominal gross output)



Range of oil price cases represents uncertainty in world oil markets

Figure 49. Brent crude oil spot prices in three cases, 1990-2040 (2011 dollars per barrel)



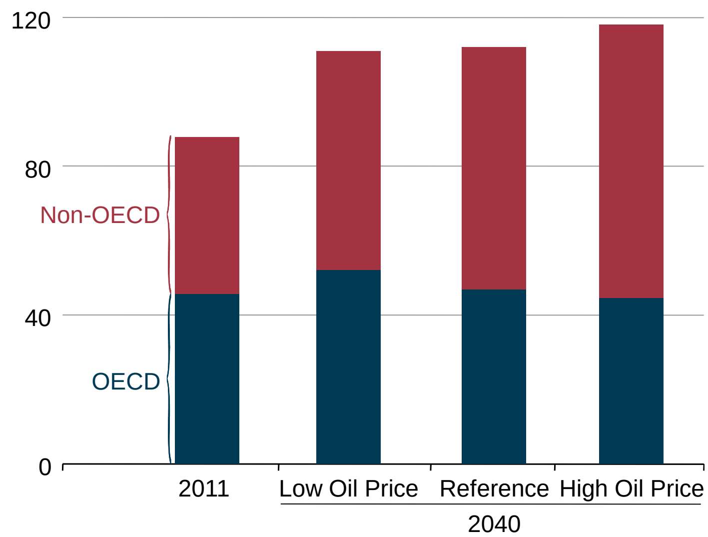
In *AEO2013*, the Brent crude oil price is tracked as the main benchmark for world oil prices. The West Texas Intermediate (WTI) crude oil price has recently been discounted relative to other world benchmark crude prices. The recent growth in U.S. mid-continental oil production has exceeded the capacity of the oil transportation infrastructure out of Cushing, Oklahoma, the market center for WTI prices. The U.S. Energy Information Administration (EIA) expects the WTI price to approach levels near the Brent price as new oil pipeline capacity is added and begins operation.

Future oil prices are uncertain. EIA develops three oil price cases—Reference, High, and Low—to examine how alternative price paths could affect future energy markets (Figure 49). The *AEO2013* price cases were developed by changing assumptions about four key factors: (1) the economics of petroleum liquids supply from countries outside the Organization of the Petroleum Exporting Countries (non-OPEC), (2) OPEC investment and production decisions, (3) the economics of other nonpetroleum liquids supply, and (4) world demand for petroleum and other liquids.

Relative to the Reference case, the Low Oil Price case assumes lower levels of world economic growth and liquid fuels demand, as well as more abundant and less costly non-OPEC liquid fuels supply. In the Low Oil Price case, OPEC supplies 49 percent of the world's liquid fuels in 2040, compared with 43 percent in the Reference case. The High Oil Price case assumes higher levels of world economic growth and liquid fuels demand, along with less abundant and more costly non-OPEC liquid fuels supply. In the High Oil Price case, OPEC supplies 40 percent of the world's liquid fuels in 2040.

Trends in petroleum and other liquids markets are defined largely by the developing nations

Figure 50. World petroleum and other liquids consumption by region in three cases, 2011 and 2040 (million barrels per day)



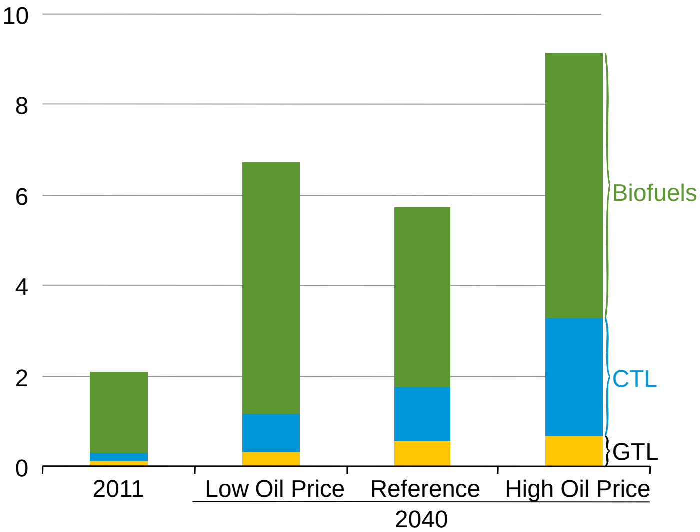
In the *AEO2013* Reference, High Oil Price, and Low Oil Price cases, total world consumption of petroleum and other liquids in 2040 ranges from 111 to 118 million barrels per day (Figure 50). The alternative oil price cases reflect shifts in both supply and demand. Although demand at the margin in the Organization for Economic Cooperation and Development (OECD) countries is influenced primarily by price, demand in non-OECD regions, where future growth in world demand is concentrated, is driven primarily by rates of economic growth that are particularly uncertain. The *AEO2013* Low Oil Price case reflects a scenario where slightly weaker economic growth limits non-OECD oil demand growth.

OECD petroleum and other liquids use grows in the Reference case to 47 million barrels per day in 2040, while non-OECD use grows to 65 million barrels per day. In the Low Oil Price case, OECD petroleum and other liquids use in 2040 is higher than in the Reference case, at 52 million barrels per day, but demand in the slow-growing non-OECD economies rises to only 59 million barrels per day. In the High Oil Price case, OECD consumption grows to 45 million barrels per day in 2040, and fast-growing non-OECD use—driven by higher GDP growth—increases to 73 million barrels per day in 2040.

The supply response also varies across the price cases. In the Low Oil Price case, OPEC's ability to manage its market share is weakened. Low prices have a negative impact on non-OPEC petroleum supply in comparison with the Reference case. In the High Oil Price case, OPEC restricts production, non-OPEC petroleum resources become more economical, and high oil prices make other liquids more economically attractive.

Production of liquid fuels from biomass, coal, and natural gas increases

Figure 51. World production of liquids from biomass, coal, and natural gas in three cases, 2011 and 2040 (million barrels per day)



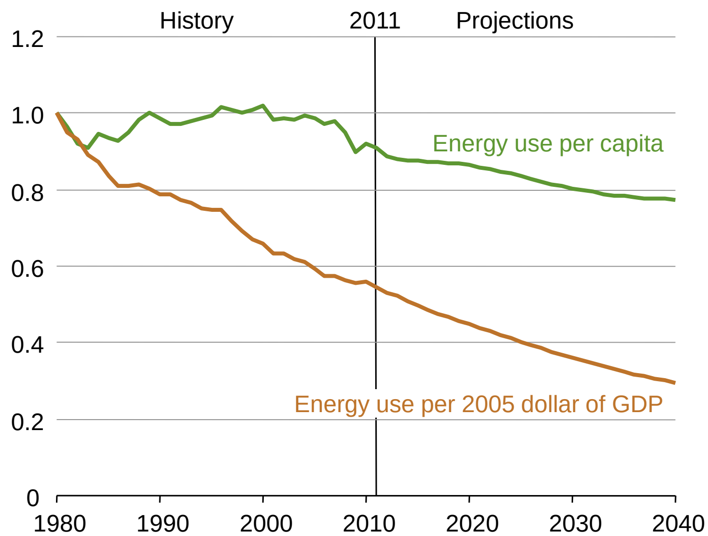
In 2011, world production of liquid fuels from biomass, coal, and natural gas totaled 2.1 million barrels per day, or about 2 percent of the energy supplied by all liquid fuels. In the *AEO2013* Reference case, production from the three sources grows to 5.7 million barrels per day in 2040 (Figure 51), or about 4 percent of the energy supplied by all liquid fuels.

In the Low Oil Price case, production of liquid fuels from these sources grows to 6.7 million barrels per day in 2040, as technology development is faster than projected in the Reference case, making the liquids easier to produce at lower cost, and demand for ethanol for use in existing blend ratios is higher. In the High Oil Price case, production grows to 9.1 million barrels per day in 2040, as higher prices stimulate greater investment in advanced liquid fuels technologies.

Across the three oil price cases, the largest contributions to production of advanced liquid fuels come from U.S. and Brazilian biofuels. In the Reference case, biofuel production totals 4.0 million barrels per day in 2040, and production of gas-to-liquids (GTL) and coal-to-liquids (CTL) fuels accounts for 1.7 million barrels per day of additional production in 2040. Biofuels production in 2040 totals 5.5 million barrels per day in the Low Oil Price case and 5.9 million barrels per day in the High Oil Price case. The projections for CTL and GTL production are more sensitive to world oil prices, varying from 1.2 million barrels per day in the Low Oil Price case to 3.3 million barrels per day in the High Oil Price case in 2040. In the Reference case, the U.S. share of world GTL production in 2040 is 36 percent, as recent developments in domestic shale gas supply have contributed to optimism about the long-term outlook for U.S. GTL plants.

In the United States, average energy use per person declines from 2011 to 2040

Figure 52. Energy use per capita and per dollar of gross domestic product, 1980-2040 (index, 1980 = 1)



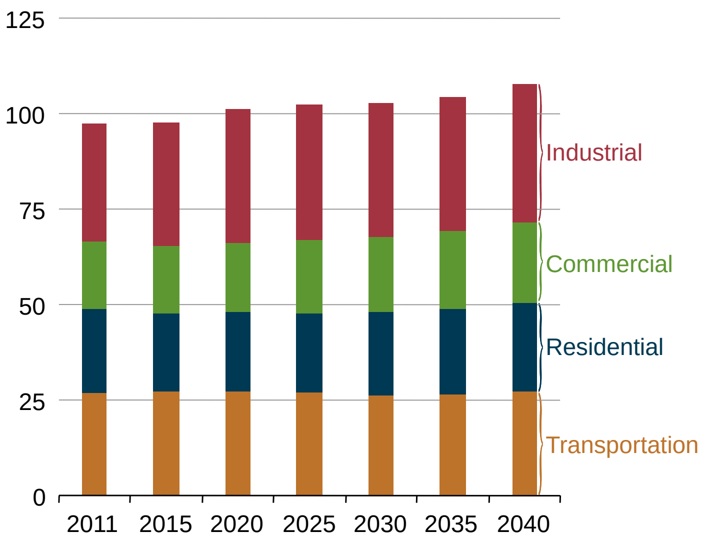
Population growth affects energy use through increases in housing, commercial floorspace, transportation, and economic activity. The effects can be mitigated, however, as the structure and efficiency of the U.S. economy change. In the *AEO2013* Reference case, U.S. population increases by 0.9 percent per year from 2011 to 2040; the economy, as measured by GDP, increases at an average annual rate of 2.5 percent; and total energy consumption increases by 0.3 percent per year. As a result, energy intensity, measured both as energy use per person and as energy use per dollar of GDP, declines through the projection period (Figure 52).

The decline in energy use per capita is brought about largely by gains in appliance efficiency and an increase in vehicle efficiency standards by 2025. From 1970 through 2008, energy use dipped below 320 million Btu per person for only a few years in the early 1980s. In 2011, energy use per capita was about 312 million Btu. In the Reference case, it declines to less than 270 million Btu per person in 2034—a level not seen since 1963.

After some recovery through 2020, the economy continues to shift away from manufacturing (particularly, energy-intensive industries such as iron and steel, aluminum, bulk chemicals, and refineries) toward service industries. The energy-intensive industries, which represented about 5.9 percent of total shipments in 2011, represent 4.4 percent in 2040 in the Reference case. Efficiency gains in the electric power sector also reduce overall energy intensity, as older, less efficient generators are retired as a result of slower growth in electricity demand, changing dispatch economics related to fuel prices and stricter environmental regulations.

Industrial and commercial sectors lead U.S. growth in primary energy use

Figure 53. Primary energy use by end-use sector, 2011-2040 (quadrillion Btu)



Total primary energy consumption, including fuels used for electricity generation, grows by 0.3 percent per year from 2011 to 2040, to 107.6 quadrillion Btu in 2040 in the *AEO2013* Reference case (Figure 53). The largest growth, 5.1 quadrillion Btu from 2011 to 2040, is in the industrial sector, attributable to increased use of natural gas in some industries (bulk chemicals, for example) as a result of an extended period of relatively low prices coinciding with rising shipments in those industries. The industrial sector was more severely affected than the other end-use sectors by the 2007-2009 economic downturn; the increase in industrial energy consumption from 2008 through 2040 is 3.9 quadrillion Btu.

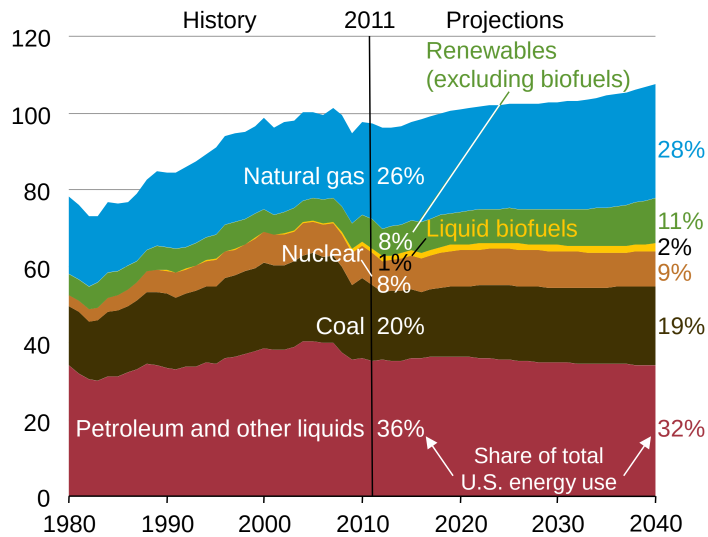
The second-largest increase in total primary energy use, at 3.1 quadrillion Btu from 2011 to 2040, is in the commercial sector, which currently accounts for the smallest share of end-use energy demand. Even as standards for building shells and energy efficiency are being tightened in the commercial sector, the growth rate for commercial energy use, at 0.5 percent per year, is the highest among the end-use sectors, propelled by 1.0-percent average annual growth in commercial floorspace.

Primary energy use in the residential sector grows by 0.2 percent per year, or about 1.6 quadrillion Btu from 2011 to 2040, but it does not increase above the 2011 level until 2029. Increased efficiency reduces energy use for space heating, lighting, and clothes washers.

In the transportation sector, light-duty vehicle (LDV) energy consumption declines as a result of the impact of fuel economy standards through 2025. Total transportation sector energy use is essentially flat from 2011 through 2040, increasing by about 140 trillion Btu.

Renewables and natural gas lead rise in primary energy consumption

Figure 54. Primary energy use by fuel, 1980-2040 (quadrillion Btu)



The aggregate fossil fuel share of total energy use falls from 82 percent in 2011 to 78 percent in 2040 in the Reference case, while renewable use grows rapidly (Figure 54). The renewable share of total energy use (including biofuels) grows from 9 percent in 2011 to 13 percent in 2040 in response to the federal renewable fuels standard; availability of federal tax credits for renewable electricity generation and capacity during the early years of the projection; and state renewable portfolio standard (RPS) programs.

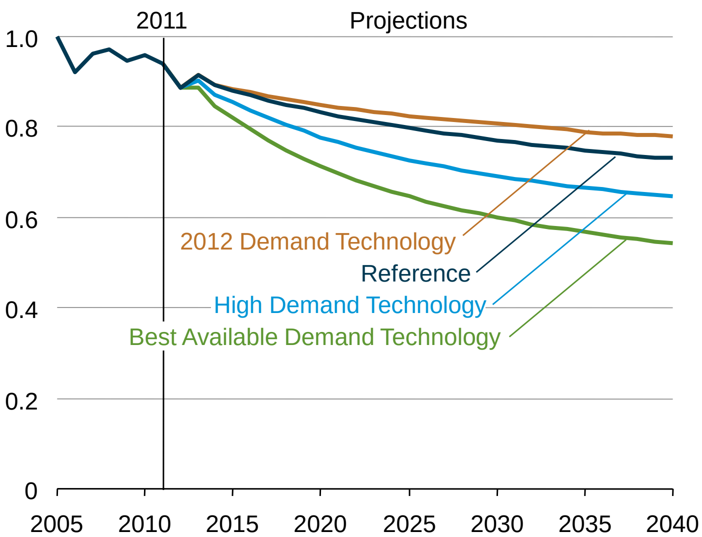
Natural gas consumption grows by about 0.6 percent per year from 2011 to 2040, led by the increased use of natural gas in electricity generation and, at least through 2020, the industrial sector. Growing production from tight shale keeps natural gas prices below their 2005-2008 levels through 2036. In the *AEO2013* Reference case, the amount of liquid fuels made from natural gas (360 trillion Btu) is about three times the amount made from coal.

Increased vehicle fuel economy offsets growth in transportation activity, resulting in a decline in the petroleum and other liquids share of fuel use even as consumption of liquid biofuels increases. Biofuels, including biodiesel blended into diesel, E85, and ethanol blended into motor gasoline (up to 15 percent), account for 6 percent of all petroleum and other liquids consumption by energy content in 2040.

Coal consumption increases at an average rate of 0.1 percent per year from 2011 to 2040, remaining below 2011 levels until 2030. By the end of 2015, a total of 6.1 gigawatts of coal-fired power plant capacity currently under construction comes on line, and another 1.5 gigawatts is added after 2016 in the Reference case, including 0.9 gigawatts with carbon sequestration capability. Additional coal is consumed in the CTL process and to produce heat and power (including electricity generation at CTL plants).

Residential energy intensity continues to decline across a range of technology assumptions

Figure 55. Residential delivered energy intensity in four cases, 2005-2040 (index, 2005 = 1)



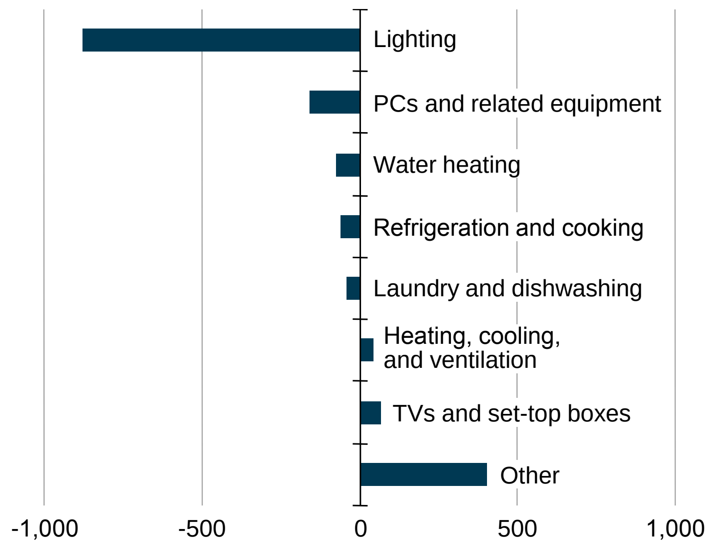
In the *AEO2013* Reference case, the energy intensity of residential demand, defined as annual energy use per household, declines from 97.2 million Btu in 2011 to 75.5 million Btu in 2040 (Figure 55). The projected 22-percent decrease in intensity occurs along with a 32-percent increase in the number of homes. Residential energy intensity is affected by various factors—for example, population shifts to warmer and drier climates, improvements in the efficiency of building construction and equipment stock, and the attitudes and behavior of residents toward energy savings.

Three alternative cases show the effects of different technology assumptions on residential energy intensity. The 2012 Demand Technology case assumes no future improvement in efficiency for equipment or building shells beyond what is available in 2012. The High Demand Technology case assumes higher efficiency, earlier availability, lower cost, and more frequent energy-efficient purchases for some equipment. The Best Available Demand Technology case limits customer purchases of new and replacement equipment to the most efficient models available at the time of purchase—regardless of cost. This case also assumes that new homes are constructed to the most energy-efficient specifications.

From 2011 to 2040, household energy intensity declines by 31 percent in the High Demand Technology case and by 42 percent in the Best Available Demand Technology case. In the 2012 Demand Technology case, energy intensity is slightly higher than in the Reference case but still declines by 17 percent from 2011 to 2040 as a result of the replacement of pre-2012 appliance stocks with 2012 vintage equipment.

Electricity use per household declines from 2011 to 2040 in the Reference case

Figure 56. Change in residential electricity consumption for selected end uses in the Reference case, 2011-2040 (kilowatthours per household)



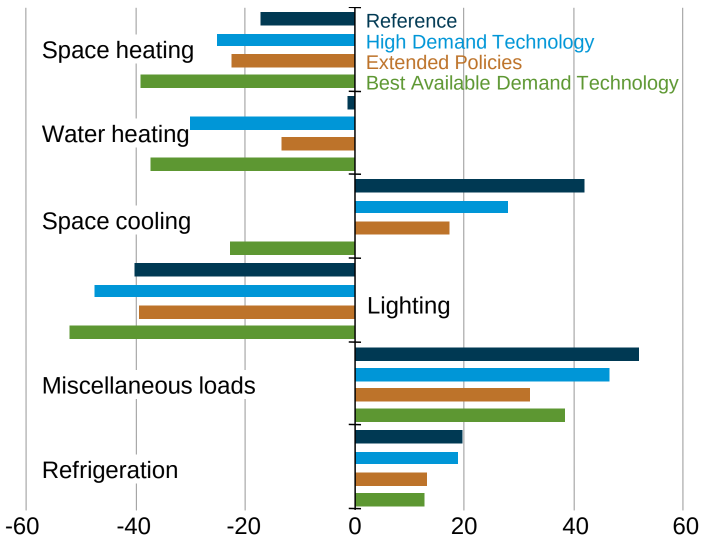
Average electricity demand per household declines by 6 percent in the Reference case, from 12.3 megawatthours in 2011 to 11.5 megawatthours in 2040. As the number of households grows, however, total delivered electricity consumption in the residential sector increases by about 24 percent. Over the same period, residential use of natural gas falls by 12 percent, and use of petroleum and other liquids falls by 25 percent. Total energy demand for most electric end uses increases, even as it declines on a per-household basis. In 2040, space cooling and "other uses" consume 42 percent and 52 percent more electricity, respectively, than in 2011 and remain the largest residential uses of electricity. Electricity use for personal computers (PCs) and related equipment and for clothes washers declines.

The largest reduction in residential electricity use is for lighting (Figure 56). The Energy Independence and Security Act of 2007 (EISA2007) phases in standards that require a reduction of about 30 percent in energy use for general-service lamps between 2012 and 2014, with specific dates that vary by light level. On January 1, 2013, the requirements went into effect for 75-watt incandescent bulbs; the requirements for 100-watt incandescent bulbs went into effect a year earlier. The EISA2007 standards result in the replacement of incandescent bulbs with more efficient compact fluorescent lighting and light-emitting diode (LED) lamps.

Among electric end-use services in the residential sector, lighting demand declines at the fastest rate (1.8 percent per year) and "other uses" rise at the fastest rate (1.4 percent per year). The growth in other uses stems from the introduction of new electrical devices in households, with little coverage by efficiency standards. Electricity use for water heating also increases, but at a slower rate (0.7 percent per year) than the growth in number of households (1.0 percent per year).

Efficiency can offset increases in residential service demand

Figure 57. Change in residential delivered energy consumption for selected end uses in four cases, 2011-2040 (percent)



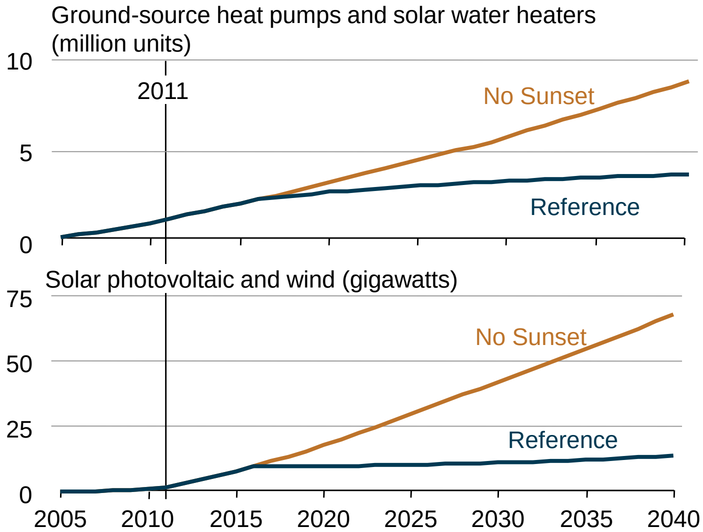
The number of households increases by 32 percent, and total residential square footage increases by 41 percent from 2011 to 2040 in the *AEO2013* Reference case. Without efficiency improvements, energy demand for uses such as heating, cooling, and lighting would increase at similar rates; however, for many end uses, delivered energy consumption increases more slowly or, in some instances, declines in the Reference case. Three alternative cases show how efficiency improvements could affect energy consumption levels (Figure 57). The High Demand Technology and Best Available Demand Technology cases assume different levels of efficiency improvement without anticipating new appliance standards. The Extended Policies case assumes the enactment of new rounds of standards, generally based on improvements seen in current ENERGY STAR equipment.

Energy consumption declines in the Reference case for two major end uses, space heating and water heating. Energy use for space cooling in the Reference case grows by 42 percent from 2011 to 2040—faster than the number of households, reflecting both population shifts and changes in the number of degree days. In the Best Available Demand Technology case, which includes greater adoption of efficient space cooling equipment, energy use for space cooling declines over the same period.

In all four cases, substantial declines in energy use for lighting reflect EISA2007 efficiency standards. For the category of miscellaneous loads—a wide range of small appliances and electronics, most of which are not currently subject to efficiency standards—delivered energy use increases at the same rate as the number of households in the Extended Policies case (32 percent from 2011 to 2040) and more rapidly than the number of households in the Reference, High Demand Technology, and Best Available Demand Technology cases because of more limited efficiency improvement.

Planned expiration of tax credits affects renewable energy use in the residential sector

Figure 58. Residential sector adoption of renewable energy technologies in two cases, 2005-2040



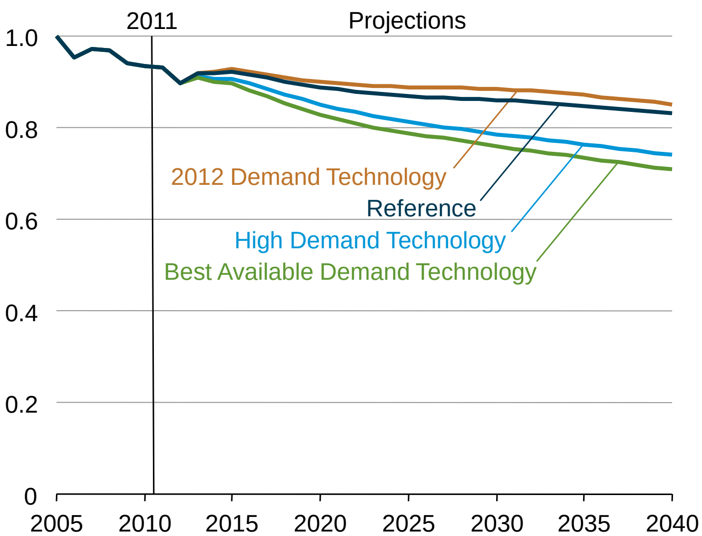
Consistent with current law, existing investment tax credits (ITCs) for residential households installing renewable energy technologies expire at the end of 2016 in the *AEO2013* Reference case. The credits can offset 30 percent of installed costs for a variety of technologies, including solar photovoltaic (PV) and wind generators, ground-source heat pumps, and solar thermal water heaters. In the Reference case, expiration of the ITCs drastically slows adoption of renewable technologies. In the *AEO2013* No Sunset case, the ITCs are extended through 2040, and the adoption of renewable technologies continues to rise (Figure 58).

In the Reference case, combined PV and wind capacity in the residential sector grows from 1.1 gigawatts in 2011 to 9.5 gigawatts in 2016. After 2016, expiration of the ITCs results in slower growth, with an additional 4.1 gigawatts added from 2017 through 2040. In the No Sunset case, more than 58 gigawatts of residential PV and wind capacity is added over the same period. In all cases, the majority of the added capacity is solar PV rather than wind.

Expiration of the ITCs also affects the penetration of renewable space-conditioning and water-heating equipment. With a 30-percent tax credit available, the number of ground-source heat pumps and solar water heaters grows from a combined 1.3 million units in 2011 to 2.4 million units in 2016; but after 2016 only 1.4 million additional units are added through 2040 in the Reference case. Even in the more optimistic No Sunset case, however, the two renewable technologies are adopted in only a small percentage of households—fewer than 6 percent—by 2040. In the No Sunset case, with the ITC extended, 6.4 million additional units are installed after 2016.

For commercial buildings, pace of decline in energy intensity depends on technology

Figure 59. Commercial delivered energy intensity in four cases, 2005-2040 (index, 2005 = 1)



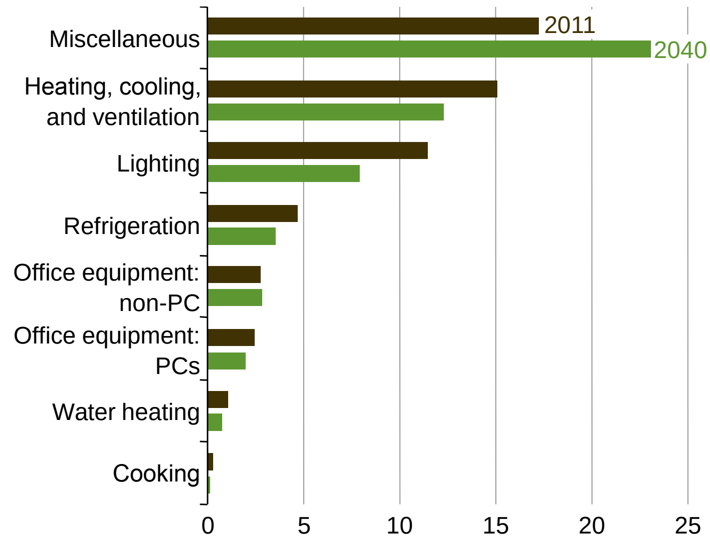
Average delivered energy consumption per square foot of commercial floorspace declines at an annual rate of 0.4 percent from 2011 to 2040 in the *AEO2013* Reference case (Figure 59), while commercial floorspace grows by 1.0 percent per year. Natural gas consumption increases at about one-half the rate of delivered electricity consumption, which grows by 0.8 percent per year in the Reference case. With ongoing improvements in equipment efficiency and building shells, the growth of energy consumption declines more rapidly than commercial floorspace increases, and the average energy intensity of commercial buildings is reduced.

Three alternative technology cases show the effects of efficiency improvements on commercial energy consumption. The 2012 Demand Technology case limits equipment and building shell efficiencies in later years to those available in 2012. The High Demand Technology case assumes earlier availability, lower costs, and higher efficiencies for equipment and building shells, and a 7-percent real discount rate for energy efficiency investments. The Best Available Demand Technology case assumes more efficient building shells for new and existing buildings than in the High Demand Technology case and limits replacement of new equipment to the most efficient models available in any given year.

The intensity of commercial energy use in the Reference case declines by 10.8 percent, from 105.2 thousand Btu per square foot in 2011 to 93.8 thousand Btu per square foot in 2040. By comparison, average commercial energy intensity drops by about 8.6 percent in the 2012 Demand Technology case, to 96.1 thousand Btu per square foot in 2040, by 20.5 percent in the High Demand Technology, and by 23.9 percent in the Best Available Demand Technology case.

Greatest reduction in energy intensity is in commercial lighting

Figure 60. Energy intensity of selected commercial electric end uses, 2011 and 2040 (thousand Btu per square foot)



Commercial energy intensity, defined as the ratio of energy consumption to floorspace, decreases for most electric end uses from 2011 to 2040 in the *AEO2013* Reference case (Figure 60). In 2011, electricity accounted for 52.4 percent of total commercial delivered energy use. Through the projection period, electricity use for lighting declines as a portion of total energy consumption in the Reference case. Advances in solid-state lighting technologies yield lamps with higher efficacy and lower cost, as well as products that can replace, or be retrofitted into, a wide variety of fixture types. As a result, the share of purchased electricity consumption used for lighting declines from 20.8 percent in 2011 to 15.1 percent in 2040 in the Reference case.

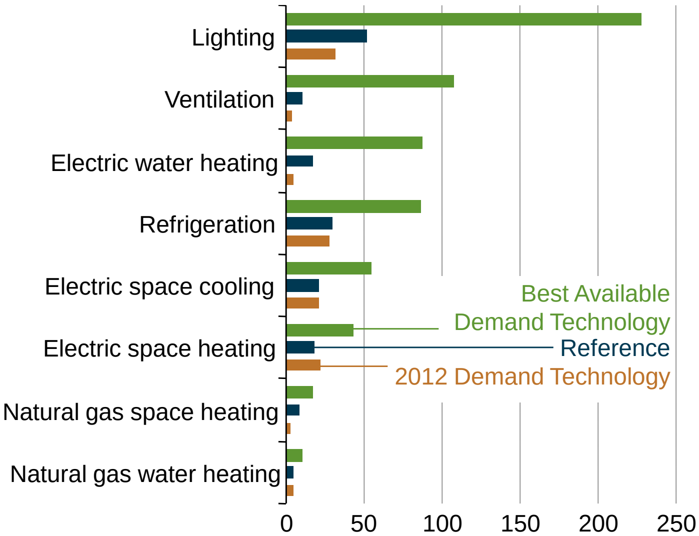
Commercial floorspace grows by an average of 1.0 percent per year from 2011 to 2040. Federal efficiency standards, which help to foster technological improvements in end uses such as space heating and cooling, water heating, refrigeration, and lighting, act to limit growth in energy consumption to less than the growth in commercial floorspace. Increasing energy use for miscellaneous electric loads, many of which currently are not subject to federal standards, leads to a 33.9-percent increase in energy intensity from 2011 to 2040 for "other" end uses in the Reference case. Miscellaneous electric loads in the commercial sector include medical equipment and video displays, among many other devices.

Although the recent recession slowed the rate of installation of new data centers, growing demand for web-based services continues to drive growth in energy use for non-PC office equipment, which increases by an average of 1.1 percent per year from 2011 to 2040. Improvements in data center cooling and ventilation equipment, as well as increased server efficiency, continue to moderate the increase.

Commercial sector energy demand

Efficiency gains for advanced technologies reduce commercial energy consumption growth

Figure 61. Efficiency gains for selected commercial equipment in three cases, 2040 (percent change from 2011 installed stock efficiency)



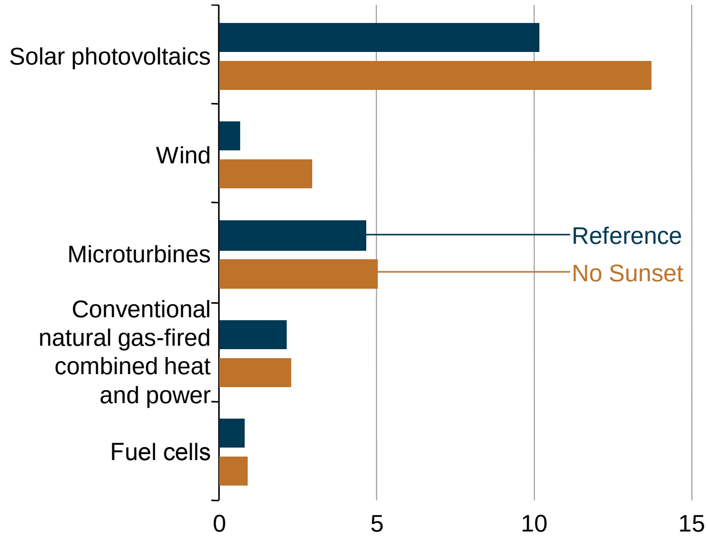
In the *AEO2013* Reference case, delivered energy use for core commercial end uses (space heating, space cooling, ventilation, water heating, lighting, cooking, and refrigeration) falls by an average of 0.1 percent per year from 2011 to 2040, even as commercial floorspace increases by 1 percent annually. The share of commercial delivered energy consumption accounted for by the core end uses, which have been the focus of a number of energy efficiency standards, falls from 60 percent in 2011 to 50 percent in 2040. Energy consumption for the remaining end uses grows by 1.4 percent per year, led by other uses of electricity and by non-PC office equipment, including servers.

The largest efficiency gains in the Reference case are expected for lighting as a result of updated cost projections for advanced LED technologies, especially after 2030. Significant gains also are projected for refrigeration, based on provisions in the Energy Policy Act of 2005 and EISA2007, space cooling, electric space heating, and electric water heating (Figure 61).

The Best Available Demand Technology case demonstrates significant potential for further improvements—especially in electric equipment. In this case, the core end uses account for only 43 percent of total delivered energy use in 2040, when their total delivered energy use is more than 1 quadrillion Btu lower than projected in the Reference case. More than 30 percent of the reduction in demand is attributed to lighting, followed by ventilation and space heating. Additional efficiency gains for commercial lighting arise from earlier and more widespread penetration of LED technologies. Other notable contributions result from high-efficiency versions of variable air volume ventilation systems and chillers for space cooling. Overall, delivered energy consumption in 2040 in the Best Available Demand Technology case is only 0.1 quadrillion Btu higher than in 2011, despite a 33-percent increase in commercial floorspace.

Renewable energy fuels most additions to commercial distributed generation capacity

Figure 62. Additions to electricity generation capacity in the commercial sector in two cases, 2011-2040 (gigawatts)



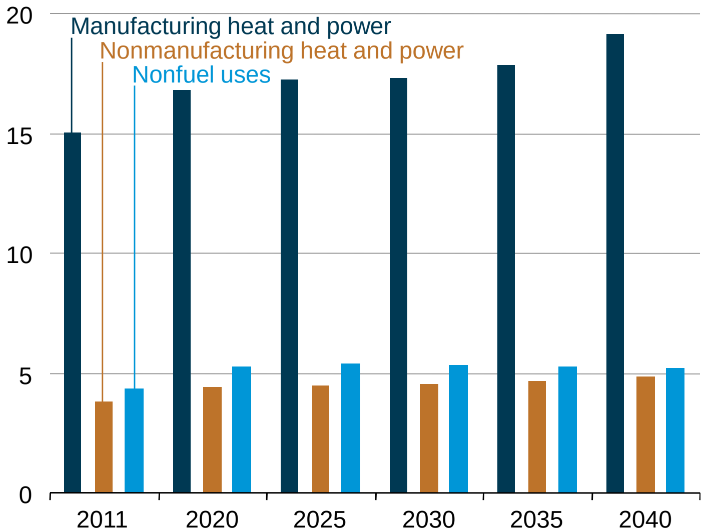
PV and wind account for 58.7 percent of commercial distributed generation capacity in 2040 in the *AEO2013* Reference case. Exponential growth of PV capacity has occurred in both new and existing construction during recent years as a result of utility incentives, new financing options, and the 30-percent federal ITC that reverts to 10 percent in 2017. In the Reference case, commercial PV capacity increases by 6.5 percent annually from 2011 to 2040. In the No Sunset case, with ITCs for all distributed generation technologies extended through 2040, PV capacity increases by an average of 7.4 percent per year.

Small-scale wind capacity increases by 7.4 percent per year from 2011 to 2040 in the Reference case and by an even greater 12.6 percent per year from 2011 to 2040 in the No Sunset case (Figure 62). As with PV, additional federal and local incentives help to drive growth in commercial wind capacity. Wind capacity accounts for 10.7 percent of the 28.4 gigawatts of total distributed generation capacity in 2040 in the No Sunset case, and PV accounts for 55.2 percent.

Rising fuel prices offset the effects of the 10-percent ITC on nonrenewable technologies for distributed generation. In the Reference case, microturbine capacity using natural gas grows by 15.0 percent per year on average, from 83.3 megawatts in 2011 to 4.7 gigawatts in 2040; and the growth rate in the No Sunset case is only slightly higher, at 15.3 percent. The microturbine share of total DG capacity in 2040 is 18.0 percent in the No Sunset case, as compared with 21.6 percent in the Reference case, and fuel cell capacity grows at an annual rate of roughly 10.9 percent in the Reference case and 11.3 percent in the No Sunset case.

Growth in industrial energy consumption is slower than growth in shipments

Figure 63. Industrial delivered energy consumption by application, 2011-2040 (quadrillion Btu)



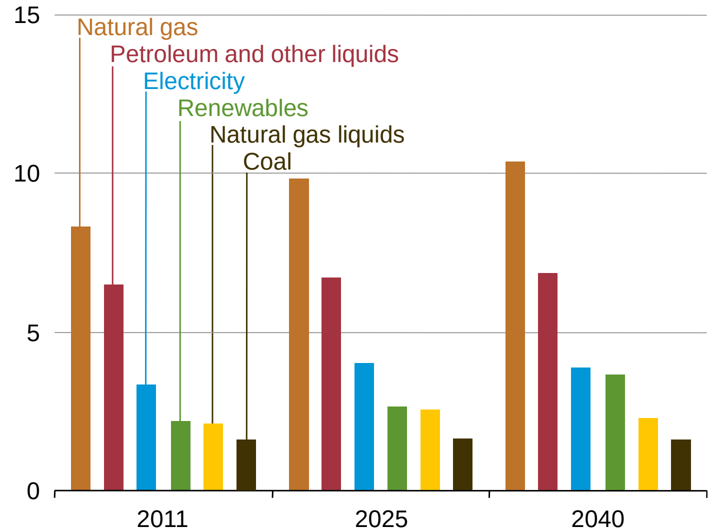
Despite a 76-percent increase in industrial shipments, industrial delivered energy consumption increases by only 19 percent from 2011 to 2040 in the *AEO2013* Reference case. The continued decline in energy intensity of the industrial sector is explained in part by a shift in the share of shipments from energy-intensive manufacturing industries (bulk chemicals, petroleum refineries, paper products, iron and steel, food products, aluminum, cement and lime, and glass) to other, less energy-intensive industries, such as plastics, computers, and transportation equipment. Also, the decline in energy intensity for the less energy-intensive industries is almost twice that for the more energy-intensive industries.

Industrial energy consumption increases by 4.7 quadrillion Btu from 2011 to 2040 in the Reference case (Figure 63), or by an average of 0.6 percent per year. Most of the growth occurs in the near term, from 2011 to 2025, with an average yearly increase of 1 percent. After 2025, the annualized rate of increase is 0.3 percent. The share of industrial delivered energy consumption used for heat and power in manufacturing increases modestly, from 63 percent in 2011 to 67 percent in 2040.

Energy consumption for heat and power in the nonmanufacturing industries (agriculture, mining, and construction) increases by about 1.1 quadrillion Btu from 2011 to 2040 in the Reference case, but its percentage of total industrial energy consumption remains at about 16 percent. Nonfuel uses of energy (feedstocks for chemical manufacturing and asphalt for construction) increase by 1.6 percent per year from 2011 to 2025 and decrease by 0.3 percent per year after 2025. The nonfuel share of energy consumption is between 18 and 20 percent over the projection period.

Reliance on natural gas, natural gas liquids, and renewables rises as industrial energy use grows

Figure 64. Industrial energy consumption by fuel, 2011, 2025, and 2040 (quadrillion Btu)



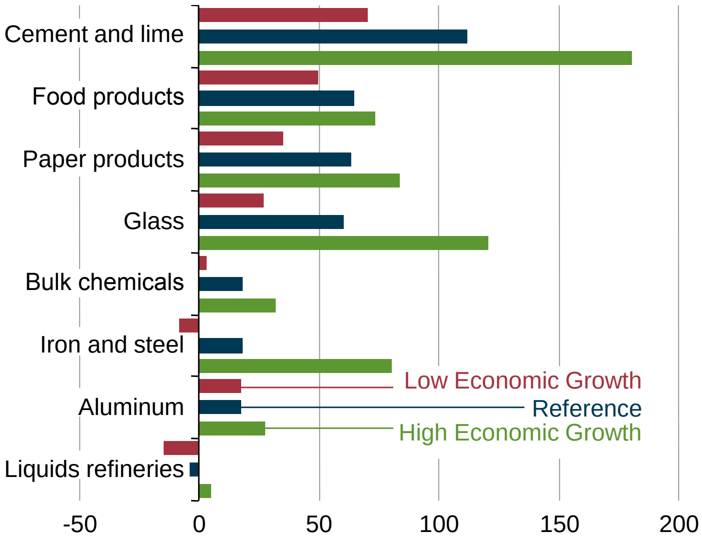
Much of the growth in industrial energy consumption in the *AEO2013* Reference case is accounted for by natural gas use, which increases by 18 percent from 2011 and 2025 and by 6 percent from 2025 to 2040 (Figure 64). With domestic natural gas production increasing sharply in the projection, natural gas prices remain relatively low. The mix of industrial fuels changes relatively slowly, however, reflecting limited capability for fuel switching in most industries.

Consumption of renewable fuels in the industrial sector grows by 22 percent from 2011 to 2025 in the Reference case and by 37 percent from 2025 to 2040. The paper industry remains the predominant consumer of renewable energy (mostly biomass) in the industrial sector. Industrial consumption of natural gas liquids (NGL) increases by 21 percent from 2011 to 2025, followed by a 9-percent decline from 2025 to 2040. NGL are consumed predominantly as feedstocks in the bulk chemicals industry and for process heat in other industries. NGL use declines starting in 2025 as shipments of bulk chemicals begin to decline in the face of increased international competition. Industrial coal use drops by less than 1 percent from 2011 to 2040, and the use of petroleum and other liquid fuels increases by 6 percent.

Low natural gas prices and increased availability of biomass contribute to growth in the use of combined heat and power (CHP). A small decline in the purchased electricity share of industrial energy consumption (less than 1 percent from 2011 to 2040) reflects growth in CHP, as well as efficiency improvements resulting from rising standards for electric motors.

Iron and steel, cement, and glass industries are most sensitive to the economic growth rate

Figure 65. Cumulative growth in value of shipments from energy-intensive industries in three cases, 2011-2040 (percent)



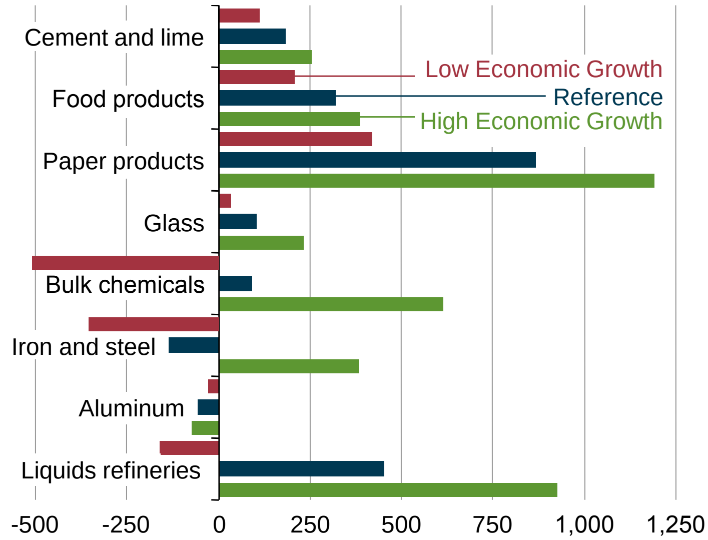
Total shipments from the energy-intensive industries grow by an average of 1.0 percent per year from 2011 to 2040 in the *AEO2013* Reference case, as compared with 0.6 percent in the Low Economic Growth case and 1.4 percent in the High Economic Growth case. Growth in shipments is uneven among the industrial subsectors.

The iron and steel, cement, and glass industries show the greatest variability in shipments across the three cases, because they supply downstream industries that are sensitive to investment, which is more variable than GDP. Construction is a downstream user of the output for all three industries, and the metal-based durables sector is a downstream industry for the iron and steel and glass industries. The high rate of shipments growth for those industries is related largely to recovery from the recent recession. Shipments of paper products grow steadily in each of the three cases (Figure 65).

The food, bulk chemicals, and aluminum industries show less variability among the three cases. Food shipments, which tend to grow in proportion to population, are less sensitive to investment. The bulk chemicals and aluminum industries face significant international competition, but they experience significant growth, largely related to relatively inexpensive natural gas and associated declines in electricity costs for aluminum manufacturers. Shipments from the petroleum refineries industry either decline or grow relatively slowly in each of the three cases as a result of slow growth in demand for petroleum-based fuels.

Energy use reflects output and efficiency trends in energy-intensive industries

Figure 66. Change in delivered energy consumption for energy-intensive industries in three cases, 2011-2040 (trillion Btu)



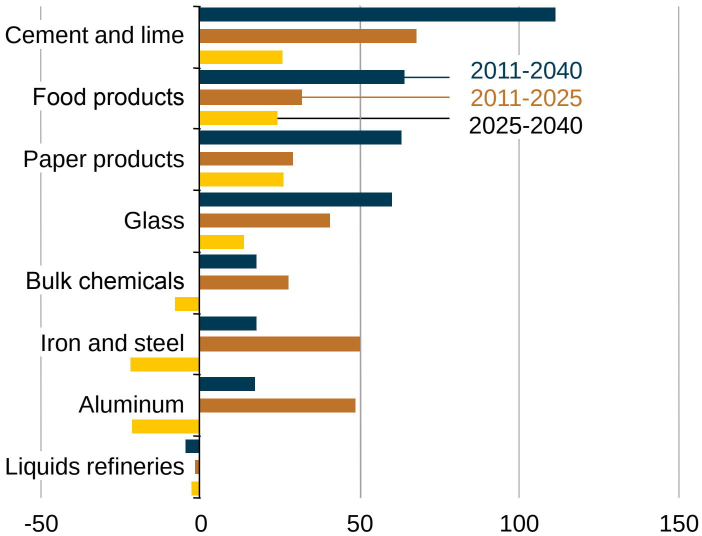
Energy consumption growth in the energy-intensive industries from 2011 to 2040 ranges from no significant change in the Low Economic Growth case to an increase of 3.9 quadrillion Btu in the High Economic Growth case (Figure 66). Energy efficiency improvements reduce the rate of growth in energy consumption relative to shipments. In the *AEO2013* Reference case, energy use in the energy-intensive industries increases by 13 percent, while shipments increase by 33 percent. In the Low Economic Growth case, energy use in the energy-intensive industries declines by 2 percent while shipments increase by 17 percent. In the High Economic Growth case, energy use grows by 27 percent and shipments by 48 percent.

Shipments from all industries grow in the Reference case, but the impact on energy consumption varies by industry because of structural changes and differences in the rate of energy efficiency improvement by industry. For example, shipments from the aluminum industry and the iron and steel industry increase in the projection, even as energy use declines. For the aluminum industry, shipments grow by 17 percent while energy use declines by 16 percent because of a rise in less energy-intensive secondary production. For the iron and steel industry, shipments grow by 18 percent while energy use declines by 10 percent because of a shift from the use of blast furnace steel production to the use of recycled products and electric arc furnaces.

Refining is the only industry subsector that shows an increase in energy intensity. Shipments from refineries fluctuate in the early years and then decline slightly after 2019, with a 4-percent decline in shipments overall from 2011 to 2040. In contrast, energy use for refining increases by 13 percent over the same period, as CTL production and the use of heavy crude feedstock, both of which are more energy-intensive to process than typical crude oil, increase after 2022.

Most of the growth in shipments from energy-intensive industries occurs before 2025

Figure 67. Cumulative growth in value of shipments from energy-intensive industries, 2011-2040, 2011-2025, and 2025-2040 (percent)



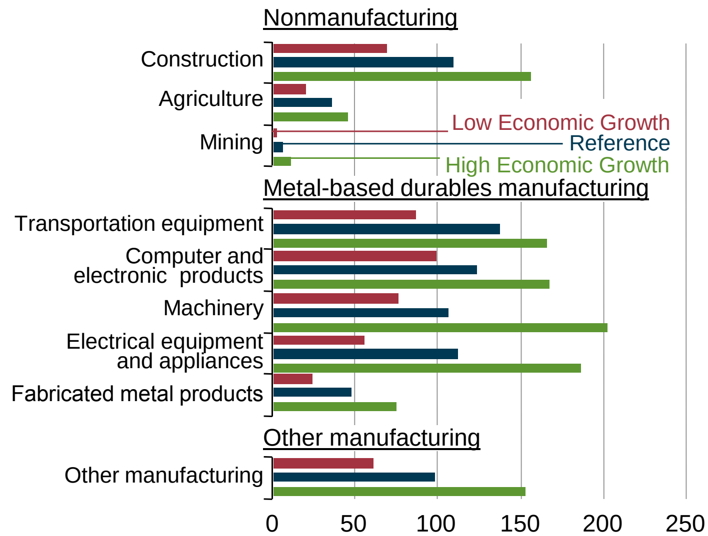
Most of the growth in shipments from energy-intensive industries from 2011 to 2040 occurs before 2025 in the Reference case (Figure 67). The strong growth in the earlier period can be explained largely by low natural gas prices that result from increased domestic production of natural gas from tight formations, as well as continued economic recovery. After 2025 the growth in shipments is weaker, with declines in some industries as a result of growing international competition and rising natural gas prices.

In the bulk chemical industry, shipments grow by 27 percent from 2011 to 2025, then decline by 8 percent from 2025 to 2040. Aluminum shipments and iron and steel shipments both grow by about 50 percent more than shipments of bulk chemicals from 2011 to 2025. The decline in aluminum and iron and steel shipments after 2025, just over 20 percent, is also greater than the decline in bulk chemicals shipments. In addition to growing international competition, the growth in industries downstream from the primary metals sector, such as construction and transportation equipment, weakens after 2025.

The cement and lime and glass industries show continued growth over the period from 2025 to 2040, but at relatively low levels. Cement and lime and glass have high shipping costs, which give domestic suppliers an advantage over imports and help to maintain the sector's growth after 2025. Shipments from the refinery industry show modest declines in both the 2011-2025 and 2025-2040 periods, as demand for transportation fuels is moderated by increasing vehicle efficiencies. The food and paper products industries show the least variation in shipment growth over the projection period, with growth rates declining modestly after 2025.

Metal-based durable goods show the fastest growth among non-energy-intensive industries

Figure 68. Cumulative growth in value of shipments from non-energy-intensive industries in three cases, 2011-2040 (percent)



In 2040, the non-energy-intensive manufacturing and nonmanufacturing industrial subsectors account for $8.5 trillion (2005 dollars) in shipments in the *AEO2013* Reference case—a 92-percent increase from 2011. The growth in those shipments from 2011 to 2040 averages 1.6 percent per year in the Low Economic Growth case and 3.0 percent per year in the High Economic Growth case, compared with 2.3 percent in the Reference case (Figure 68). Non-energy-intensive manufacturing and nonmanufacturing are segments of the industrial sector that consume fuels primarily for thermal or electrical needs, not as raw materials or feedstocks.

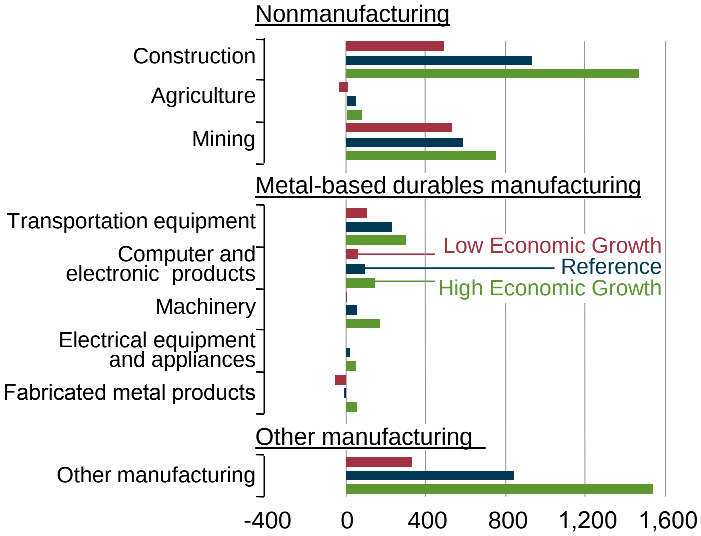
In the three cases, the annual rate of increase in shipments from non-energy-intensive industries generally is twice the rate of increase for the energy-intensive industries, primarily as a result of growing demand for high-technology, high-value goods. Further, the growth in shipments is fastest in the medium term. From 2011 to 2025, shipments of metal-based durables grow by an average of 3.2 percent per year; from 2025 to 2040, the growth rate slows to 2.1 percent per year.

In the Reference case, shipments from the non-energy-intensive industries grow at different rates. For metal-based durables, shipments grow by 2.6 percent per year from 2011 to 2040, led by 3.0-percent average annual growth for transportation equipment. In the nonmanufacturing sector, construction grows by an average of 2.6 percent per year, agriculture grows by 1.0 percent per year, and mining grows by 0.2 percent per year.

Transportation sector energy demand

Nonmanufacturing efficiency gains are slowed by rising energy intensity in the mining industry

Figure 69. Change in delivered energy consumption for non-energy-intensive industries in three cases, 2011-2040 (trillion Btu)



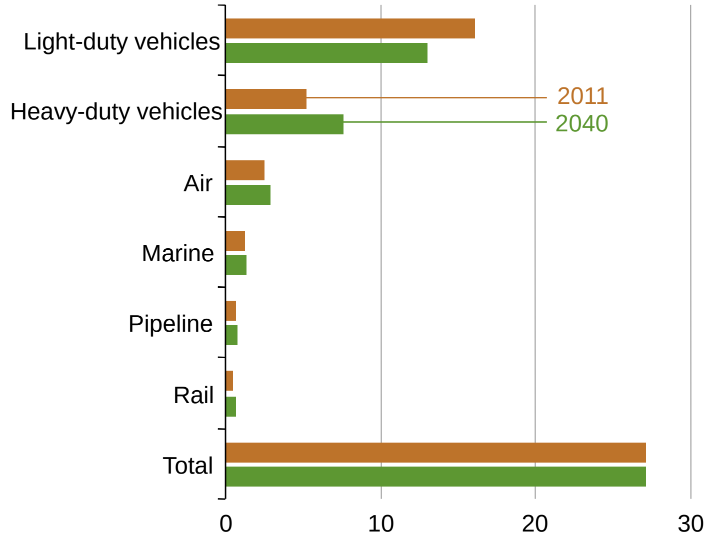
From 2011 to 2040, total energy consumption in the non-energy-intensive manufacturing and nonmanufacturing industrial subsectors increases by 18 percent (1.4 quadrillion Btu) in the Low Economic Growth case, 36 percent (2.8 quadrillion Btu) in the Reference case, and 58 percent (4.6 quadrillion Btu) in the High Economic Growth case (Figure 69).

The nonmanufacturing subsector (construction, agriculture, and mining) accounts for roughly 57 percent of the energy consumed in the non-energy-intensive industries but only 31 percent of the total shipments in 2040. The nonmanufacturing industries are more energy-intensive than the manufacturing industries, and there is no significant decline in energy intensity for the nonmanufacturing industries over the projection period. Construction and agriculture show annual declines in energy intensity from 2011 to 2040 (1.0 percent and 0.9 percent per year, respectively), whereas the energy intensity of the mining industry increased by 0.7 percent from 2011 to 2040 in the *AEO2013* Reference case. Within the nonmanufacturing sector, the mining industry accounts for 17.3 percent of shipments in 2040 and roughly 43.2 percent of the energy consumed, as the energy intensity of mining activity increases with resource depletion over time.

In comparison, the non-energy-intensive manufacturing industries—such as plastics, computers, and transportation equipment—show a 33-percent decline in energy intensity from 2011 to 2040, or an average decline of about 1.4 percent per year. For the transportation equipment industry, which accounts for 19 percent of the increase in energy use but roughly 29 percent of the increase in shipments, energy intensity declines by 1.5 percent per year on average in the Reference case.

Growth in transportation energy consumption flat across projection

Figure 70. Delivered energy consumption for transportation by mode, 2011 and 2040 (quadrillion Btu)



The transportation sector consumes 27.1 quadrillion Btu of energy in 2040, the same as the level of energy demand in 2011 (Figure 70). The projection of no growth in transportation energy demand differs markedly from the historical trend, which saw 1.1-percent average annual growth from 1975 to 2011 [*126*]. No growth in transportation energy demand is the result of declining energy use for LDVs, which offsets increased energy use for heavy-duty vehicles (HDVs), aircraft, marine, rail, and pipelines.

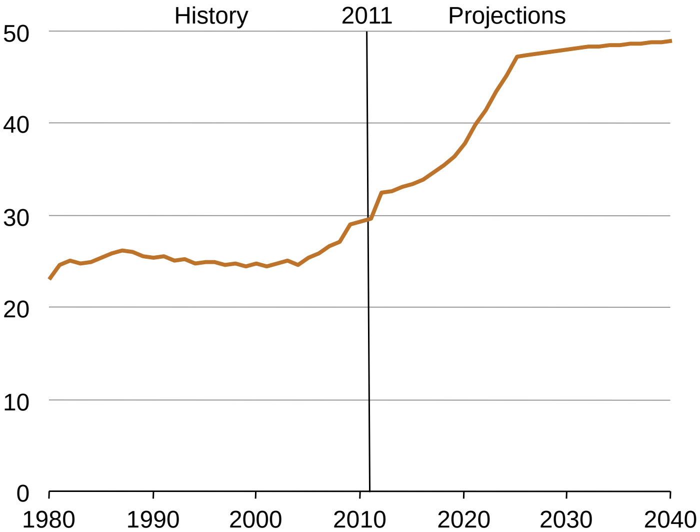
Energy demand for LDVs declines from 16.1 quadrillion Btu in 2011 to 13.0 quadrillion Btu in 2040, in contrast to 0.9-percent average annual growth from 1975 to 2011. Higher fuel economy for LDVs more than offsets modest growth in vehicle miles traveled (VMT) per driver.

Energy demand for HDVs (including tractor trailers, buses, vocational vehicles, and heavy-duty pickups and vans) increases the fastest among transportation modes, from 5.2 quadrillion Btu in 2011 to 7.6 quadrillion Btu in 2040, as a result of increased travel as economic output grows. The increase in energy demand for HDVs is tempered by standards for HDV fuel efficiency and greenhouse gas (GHG) emissions starting in 2014.

Energy demand for aircraft increases from 2.5 quadrillion Btu in 2011 to 2.9 quadrillion Btu in 2040. Increases in personal air travel are offset by gains in aircraft fuel efficiency, while air freight movement grows with higher exports. Energy consumption for marine and rail travel increases as industrial output rises, and pipeline energy use rises moderately as increasing volumes of natural gas are produced closer to end-use markets.

CAFE and greenhouse gas emissions standards boost light-duty vehicle fuel economy

Figure 71. Average fuel economy of new light-duty vehicles, 1980-2040 (miles per gallon, CAFE compliance values)

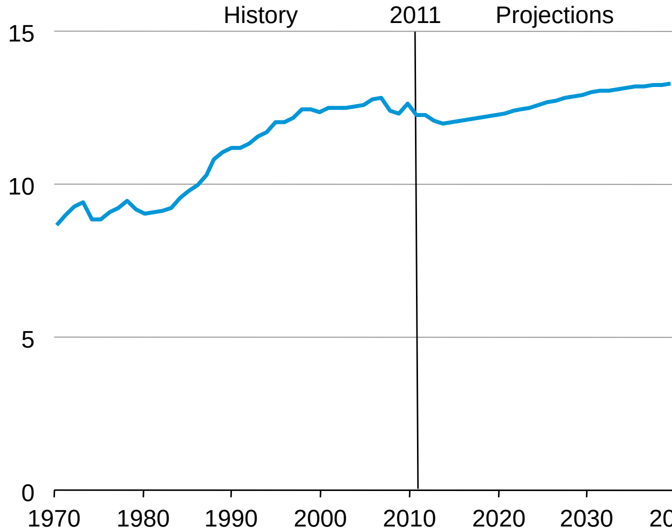


The 1978 introduction of corporate average fuel economy (CAFE) standards for LDVs increased their average fuel economy from 19.9 mpg in 1978 to 26.2 mpg in 1987. Despite technological improvement, fuel economy fell to between 24 and 27 mpg over the next two decades, as sales of light trucks increased from 18 percent of new LDV sales in 1980 to 55 percent in 2004 [*127*]. The subsequent rise in fuel prices, reduction in sales of light trucks, and more stringent CAFE standards for light-duty trucks starting in model year (MY) 2008 and for passenger cars in MY 2011, resulted in a rise in estimated LDV fuel economy to 29.0 mpg in 2011 [*128*].

The National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency have jointly announced new GHG emissions and CAFE standards for MY 2012 through MY 2025 [*129*, *130*], which are included in AEO2013. As a result, the fuel economy of new LDVs, measured in terms of their compliance values in CAFE testing [*131*], rises from 32.5 mpg in 2012 to 47.3 mpg in 2025 (Figure 71). The GHG emissions and CAFE standards are held roughly constant after 2025, but fuel economy continues to rise, to 49.0 mpg in 2040, as new fuel-saving technologies are adopted. In 2040, passenger car fuel economy averages 56.1 mpg and light-duty truck fuel economy averages 40.5 mpg.

Travel demand for personal vehicles continues to grow, but more slowly than in the past

Figure 72. Vehicle miles traveled per licensed driver, 1970-2040 (thousand miles)



Personal vehicle travel demand, measured as annual VMT per licensed driver, grew at an average annual rate of 1 percent from 1970 to 2007, from about 8,700 miles per driver in 1970 to 12,800 miles in 2007. Since peaking in 2007, travel per licensed driver has declined because of rapidly increasing fuel prices and the economic recession.

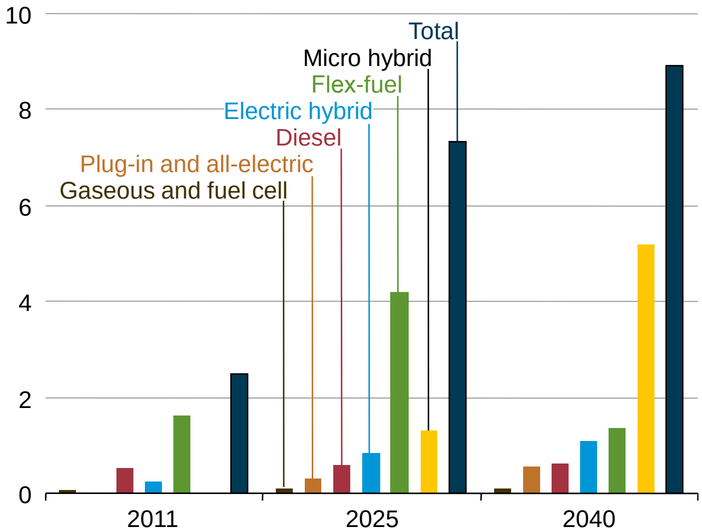
Demographic changes moderate projected growth in VMT per licensed driver, which grows by an average of 0.3 percent per year, remaining below the 2007 level until 2029 and then growing to 13,300 miles in 2040 (Figure 72). Although vehicle sales rise through 2040, the number of vehicles per licensed driver declines from the all-time peak of 1.12 in 2007 to 1.01 in 2040. Further, unemployment remains above prerecession levels until around 2020, tempering the growth in demand for personal travel.

From 2011 to 2040, the price of motor gasoline increases by 26 percent (on a Btu basis), while real disposable personal income grows by 95 percent. Faster growth in income than fuel price lowers the percentage of income spent on fuel, boosting travel demand. In addition, the increase in fuel costs is more than offset by a 50-percent improvement in new vehicle fuel economy. Implementation of the new GHG and CAFE standards for LDVs lowers the cost of driving per mile and leads to growth in personal travel demand. Personal vehicle travel demand could vary, however, depending on several uncertainties, including the impact of changing demographics on travel behavior, the intensity of mass transit use, and other factors discussed above, such as fuel prices. The implications of a possible long-term decline in VMT per licensed driver are considered in the "Issues in focus" section of this report (see "Petroleum import dependence in a range of cases").

Transportation sector energy demand

Sales of alternative fuel, fuel flexible, and hybrid vehicles sales rise

Figure 73. Sales of light-duty vehicles using non-gasoline technologies by type, 2011, 2025, and 2040 (million vehicles sold)



LDVs that use diesel, other alternative fuels, hybrid-electric, or all-electric systems play a significant role in meeting more stringent GHG emissions and CAFE standards over the projection period. Sales of such vehicles increase from 20 percent of all new LDV sales in 2011 to 49 percent in 2040 in the *AEO2013* Reference case.

Micro hybrid vehicles, defined here as conventional gasoline vehicles with micro hybrid systems that manage engine operation at idle, represent 28 percent of new LDV sales in 2040, the largest share among vehicles using diesel, alternative fuels, hybrid-electric, or all-electric systems.

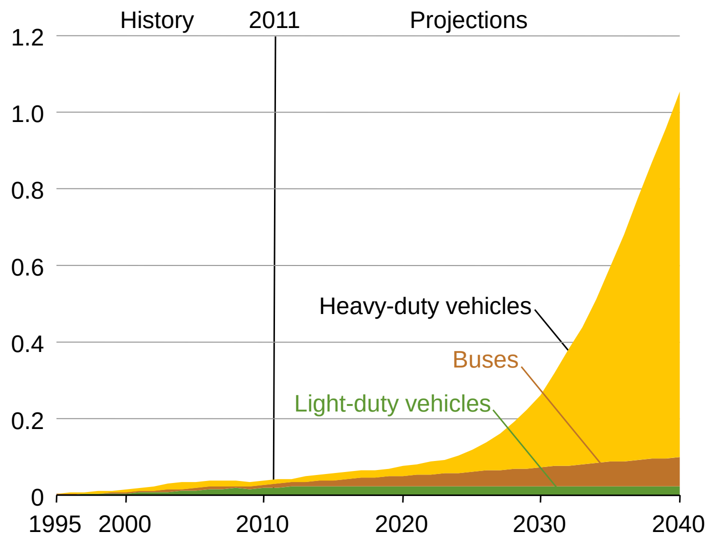
Flex-fuel vehicles (FFVs), which can use blends of ethanol up to 85 percent, represent the second largest share of these vehicle types in 2040, at 7 percent of all new LDV sales. Current incentives for manufacturers selling FFVs, which are available in the form of fuel economy credits earned for CAFE compliance, expire in 2019. As a result, the FFV share of LDV sales rises over the next decade and then declines.

Sales of hybrid electric and all-electric vehicles that use stored electric energy for motive power grow considerably in the Reference case (Figure 73). Gasoline- and diesel-electric hybrid vehicles account for 6 percent of total LDV sales in 2040; and plug-in hybrid and all-electric vehicles account for 3 percent of total LDV sales, or 6 percent of sales of vehicles using diesel, alternative fuels, hybrid, or all-electric systems.

The diesel vehicle share of total sales remains constant over the projection period at about 4 percent of total LDV sales. Light-duty gaseous and fuel cell vehicles account for less than 1 percent of new vehicle sales throughout the projection period because of limited fueling infrastructure and high incremental vehicle costs.

Heavy-duty vehicles dominate natural gas consumption in the transportation sector

Figure 74. Natural gas consumption in the transportation sector, 1995-2040 (quadrillion Btu)



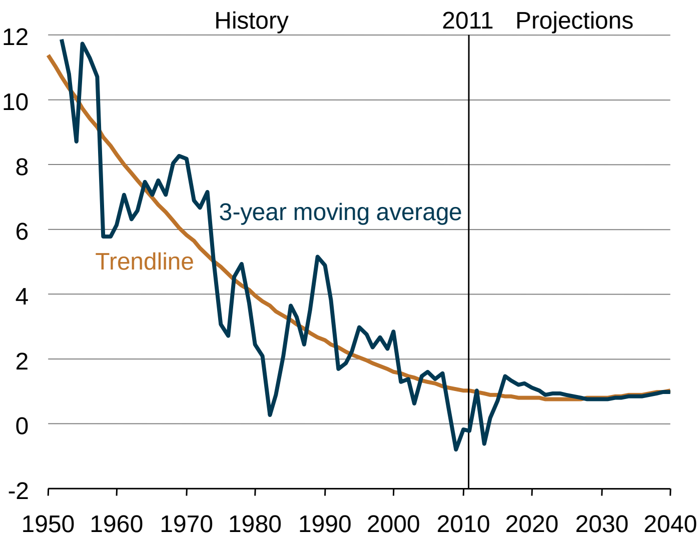
Natural gas, as compressed natural gas (CNG) and liquefied natural gas (LNG), is the fastest-growing fuel in the transportation sector, with an average annual growth rate of 11.9 percent from 2011 to 2040 (Figure 74). HDVs—which include tractor trailers, vocational vehicles, buses, and heavy-duty pickups and vans with a gross vehicle weight rating (GVWR) of 10,001 pounds or more—lead the growth in natural gas demand throughout the projection period. Natural gas fuel consumption by HDVs increases from almost zero in 2011 to more than 1 quadrillion Btu in 2040, at an average annual growth rate of 14.6 percent.

Although HDVs fueled by natural gas have significant incremental costs in comparison with their diesel-powered counterparts, the increase in natural gas consumption for HDVs is spurred by low prices of natural gas compared with diesel fuel, as well as purchases of natural gas vehicles for relatively high-VMT applications, such as tractor trailers.

The total number of miles traveled annually by HDVs grows by 82 percent in the Reference case, from 240 billion miles in 2011 to 438 billion miles in 2040, for an average annual increase of 2.1 percent. HDVs, those with a GVWR greater than 26,000 pounds (primarily tractor trailers), account for about three-fourths of truck VMT and 91 percent of natural gas consumption by all HDVs in 2040. The rise in VMT is supported by rising economic output over the projection period and an increase in the number of trucks on the road, from 9.0 million in 2011 to 13.7 million in 2040.

Growth in electricity use slows but still increases by 28 percent from 2011 to 2040

Figure 75. U.S. electricity demand growth, 1950-2040 (percent, 3-year moving average)



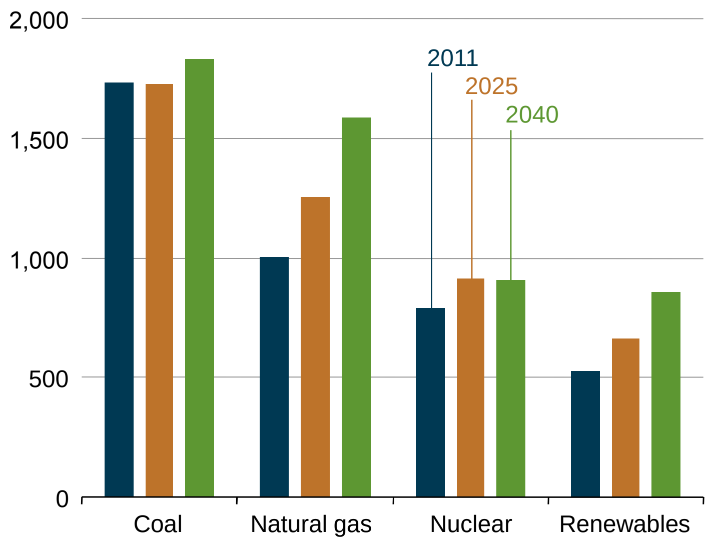
The growth of electricity demand (including retail sales and direct use) has slowed in each decade since the 1950s, from a 9.8-percent annual rate of growth from 1949 to 1959 to only 0.7 percent per year in the first decade of the 21st century. In the *AEO2013* Reference case, electricity demand growth remains relatively slow, as increasing demand for electricity services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment (Figure 75). Total electricity demand grows by 28 percent in the projection (0.9 percent per year), from 3,839 billion kilowatthours in 2011 to 4,930 billion kilowatthours in 2040.

Retail electricity sales grow by 24 percent (0.7 percent per year) in the Reference case, from 3,725 billion kilowatthours in 2011 to 4,608 billion kilowatthours in 2040. Residential electricity sales also grow by 24 percent, to 1,767 billion kilowatthours in 2040, spurred by population growth and continued population shifts to warmer regions with greater cooling requirements. Led by demand in the service industries, sales of electricity to the commercial sector increase by 27 percent, to 1,677 billion kilowatthours in 2040. Sales to the industrial sector grow by 17 percent, to 1,145 billion kilowatthours in 2040. Electricity sales to the transportation sector, although relatively small, triple from 6 billion kilowatthours in 2011 to 19 billion kilowatthours in 2040 with increasing sales of electric plug-in LDVs.

Electricity demand can vary with different assumptions about economic growth, electricity prices, and advances in energy-efficient technologies. In the High Economic Growth case, demand grows by 42 percent from 2011 to 2040, compared with 18 percent in the Low Economic Growth case and only 7 percent in the Best Available Technology case. Average electricity prices (in 2011 dollars) increase by 5 percent from 2011 to 2040 in the Low Economic Growth case and 13 percent in the High Economic Growth case, to 10.4 and 11.2 cents per kilowatthour, respectively, in 2040.

Coal-fired plants continue to be the largest source of U.S. electricity generation

Figure 76. Electricity generation by fuel, 2011, 2025, and 2040 (billion kilowatthours)



Coal-fired power plants continue to be the largest source of electricity generation in the *AEO2013* Reference case (Figure 76), but their market share declines significantly. From 42 percent in 2011, coal's share of total U.S. generation declines to 38 percent in 2025 and 35 percent in 2040. Approximately 15 percent of the coal-fired capacity active in 2011 is expected to be retired by 2040 in the Reference case, while only 4 percent of new generating capacity added is coal-fired. Existing coal-fired units that have undergone environmental equipment retrofits continue to operate throughout the projection.

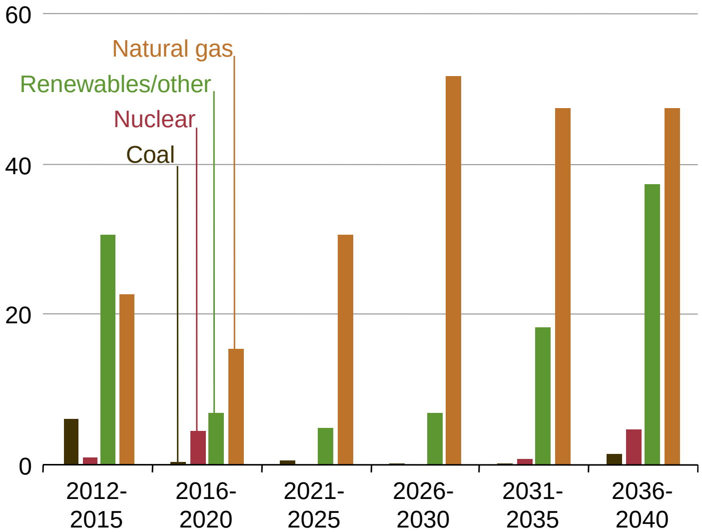
Generation from natural gas increases by an average of 1.6 percent per year from 2011 to 2040, and its share of total generation grows from 24 percent in 2011 to 27 percent in 2025 and 30 percent in 2040. The relatively low cost of natural gas makes the dispatching of existing natural gas plants more competitive with coal plants and, in combination with relatively low capital costs, makes plants fueled by natural gas an alternative choice for new generation capacity.

Generation from renewable sources grows by 1.7 percent per year on average in the Reference case, and the share of total generation rises from 13 percent in 2011 to 16 percent in 2040. The nonhydropower share of total renewable generation increases from 38 percent in 2011 to 65 percent in 2040.

Generation from U.S. nuclear power plants increases by 0.5 percent per year on average from 2011 to 2040, with most of the growth between 2011 and 2025, but the share of total U.S. electricity generation declines from 19 percent in 2011 to 17 percent in 2040, as the growth in nuclear generation is outpaced by growth in generation using natural gas and renewables.

Most new capacity additions use natural gas and renewables

Figure 77. Electricity generation capacity additions by fuel type, including combined heat and power, 2012-2040 (gigawatts)



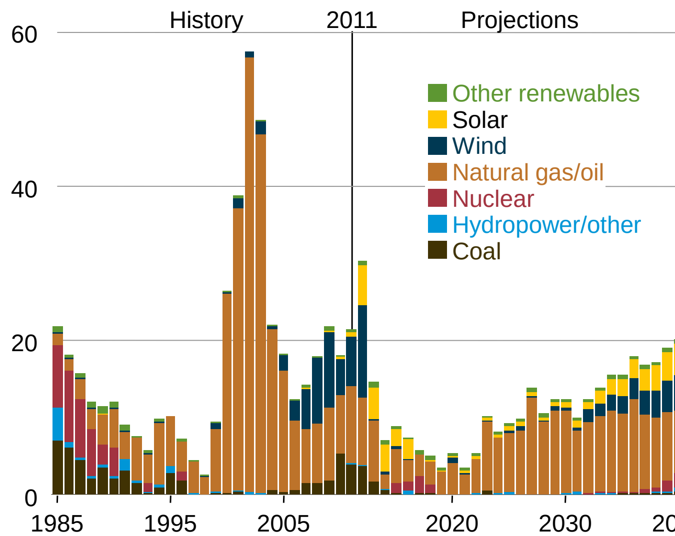
Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors [*132*]. With growing electricity demand and the retirement of 103 gigawatts of existing capacity, 340 gigawatts of new generating capacity [*133*] is added in the *AEO2013* Reference case from 2012 to 2040 (Figure 77).

Natural gas-fired plants account for 63 percent of capacity additions from 2012 to 2040 in the Reference case, compared with 31 percent for renewables, 3 percent for coal, and 3 percent for nuclear. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, federal tax incentives, state energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity. Current federal and state environmental regulations also affect the use of fossil fuels, particularly coal. Uncertainty about future limits on GHG emissions and other possible environmental programs also reduces the competitiveness of coal-fired plants (reflected in the *AEO2013* Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity).

Uncertainty about electricity demand growth and fuel prices also affects capacity planning. Total capacity additions from 2012 to 2040 range from 252 gigawatts in the Low Economic Growth case to 498 gigawatts in the High Economic Growth case. In the Low Oil and Gas Resource case, natural gas prices are higher than in the Reference case, and new natural gas-fired capacity added from 2012 to 2040 totals 152 gigawatts, or 42 percent of total additions. In the High Oil and Gas Resource case, delivered natural gas prices are lower than in the Reference case, and 311 gigawatts of new natural gas-fired capacity is added from 2012 to 2040, accounting for 82 percent of total new capacity.

Additions to power plant capacity slow after 2012 but accelerate beyond 2023

Figure 78. Additions to electricity generating capacity, 1985-2040 (gigawatts)



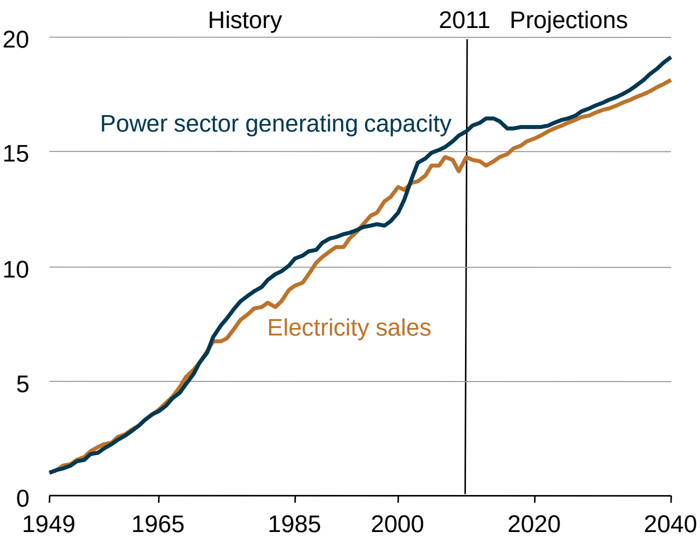
Typically, investments in electricity generation capacity have gone through boom-and-bust cycles. Periods of slower growth have been followed by strong growth in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring (Figure 78). A construction boom in the early 2000s saw capacity additions averaging 35 gigawatts a year from 2000 to 2005. Since then, average annual builds have dropped to 18 gigawatts per year from 2006 to 2011.

In the *AEO2013* Reference case, capacity additions from 2012 to 2040 total 340 gigawatts, including new plants built not only in the power sector but also by end-use generators. Annual additions in 2012 and 2013 remain relatively high, averaging 22 gigawatts per year. Of those early builds, 51 percent are renewable plants built to take advantage of federal tax incentives and to meet state renewable standards.

Annual builds drop significantly after 2013 and remain below 9 gigawatts per year until 2023. During that period, existing capacity is adequate to meet growth in demand in most regions, given the earlier construction boom and relatively slow growth in electricity demand after the economic recession. Between 2025 and 2040, average annual builds increase to 14 gigawatts per year, as excess capacity is depleted and the rate of total capacity growth is more consistent with electricity demand growth. About 68 percent of the capacity additions from 2025 to 2040 are natural gas-fired, given the higher construction costs for other capacity types and uncertainty about the prospects for future limits on GHG emissions.

Growth in generating capacity parallels rising demand for electricity

Figure 79. Electricity sales and power sector generating capacity, 1949-2040 (indexes, 1949 = 1.0)



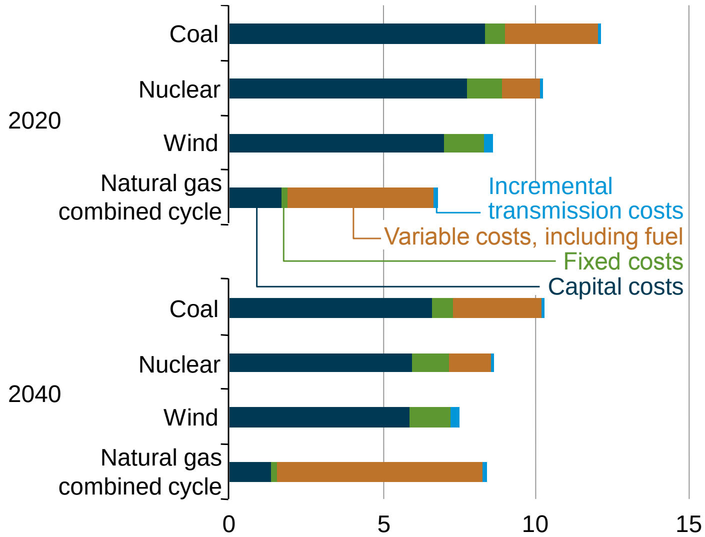
Over the long term, growth in electricity generating capacity parallels the growth in end-use demand for electricity. Unexpected shifts in demand or dramatic changes affecting capacity investment decisions can, however, cause imbalances that may take years to be worked out.

Figure 79 shows indexes summarizing relative changes in total generating capacity and electricity demand. During the 1950s and 1960s, the capacity and demand indexes tracked closely. The energy crises of the 1970s and 1980s, together with other factors, slowed electricity demand growth, and capacity growth outpaced demand for more than 10 years thereafter, as planned units continued to come on line. Demand and capacity did not align again until the mid-1990s. Then, in the late 1990s, uncertainty about deregulation of the electricity industry caused a downturn in capacity expansion, and another period of imbalance followed, with growth in electricity demand exceeding capacity growth.

In 2000, a boom in construction of new natural gas-fired plants began, bringing capacity back into balance with demand and creating excess capacity. Construction of new wind capacity that sometimes needs backup capacity because of intermittency also began to grow after 2000. More recently, the 2007-2009 economic recession caused a significant drop in electricity demand, which has yet to recover. Slow near-term growth in electricity demand in the *AEO2013* Reference case creates excess generating capacity. Capacity currently under construction is completed, but a limited amount of additional capacity is built before 2025, while older capacity is retired. By 2025, capacity growth and demand growth are in balance again, and they grow at similar rates through 2035. In the later years, total capacity grows at a rate slightly higher than demand, due in part to an increasing share of intermittent renewable capacity that does not contribute to meeting demand in the same proportion as dispatchable capacity.

Costs and regulatory uncertainties vary across options for new capacity

Figure 80. Levelized electricity costs for new power plants, excluding subsidies, 2020 and 2040 (2011 cents per kilowatthour)



Technology choices for new generating capacity are based largely on capital, operating, and transmission costs [*134*]. Coal, nuclear, and wind plants are capital-intensive (Figure 80), whereas operating (fuel) expenditures make up most of the costs for natural gas plants. Capital costs depend on such factors as equipment costs, interest rates, and cost recovery periods, which vary with technology. Fuel costs vary with operating efficiency, fuel price, and transportation costs.

In addition to considerations of levelized costs [*135*], some technologies and fuels receive subsidies, such as production or ITCs. Also, new plants must satisfy local and federal emissions standards and must be compatible with the utility's load profile.

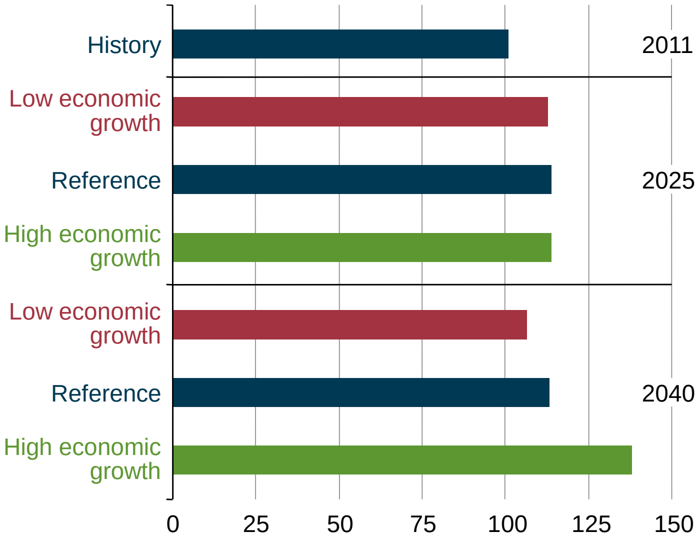
Regulatory uncertainty also affects capacity planning. New coal plants may require carbon control and sequestration equipment, resulting in higher material, labor, and operating costs. Alternatively, coal plants without carbon controls could incur higher costs for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit GHGs, their costs are not directly affected by regulatory uncertainty in this area.

Capital costs can decline over time as developers gain technology experience, with the largest rate of decline observed in new technologies. In the *AEO2013* Reference case, the capital costs of new technologies are adjusted upward initially to compensate for the optimism inherent in early estimates of project costs, then decline as project developers gain experience. The decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, resulting in reduced variable costs unless increases in fuel costs exceed the savings from efficiency gains.

Electricity capacity

Nuclear power plant capacity grows slowly through uprates and new builds

Figure 81. Electricity generating capacity at U.S. nuclear power plants in three cases, 2011, 2025, and 2040 (gigawatts)

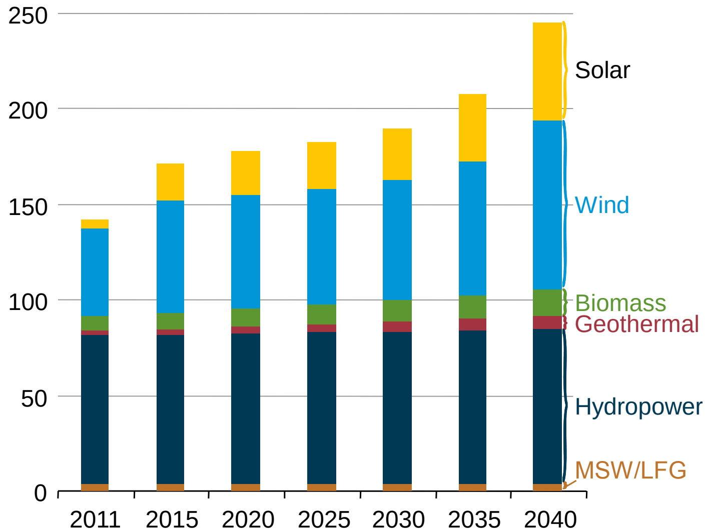


In the *AEO2013* Reference case, nuclear power capacity increases from 101.1 gigawatts in 2011 to a high of 114.1 gigawatts in 2025, before declining to 108.5 gigawatts in 2036 (Figure 81), largely as a result of plant retirements. New additions in the later years of the projection bring nuclear capacity back up to 113.1 gigawatts in 2040. The capacity increase through 2025 includes 8.0 gigawatts of expansion at existing plants and 5.5 gigawatts of new capacity, which includes completion of a conventional reactor at the Watts Bar site. Four advanced reactors, reported as under construction, also are assumed to be brought online by 2020 and to be eligible for federal financial incentives. High construction costs for nuclear plants, especially relative to natural gas-fired plants, make additional options for new nuclear capacity uneconomical until the later years of the projection, when an additional 5.5 gigawatts is added. Nuclear capacity additions vary with assumptions about overall demand for electricity. Across the Economic Growth cases, net additions of nuclear capacity from 2012 to 2040 range from 5.5 gigawatts in the Low Economic Growth case to 36.1 gigawatts in the High Economic Growth case.

One nuclear unit, Oyster Creek, is expected to be retired at the end of 2019, as announced by Exelon in December 2010. An additional 6.5 gigawatts of nuclear capacity is assumed to be retired by 2036 in the Reference case. All other existing nuclear units continue to operate through 2040 in the Reference case, which assumes that they will apply for and receive operating license renewals, including in some cases a second 20-year extension after 60 years of operation (for more discussion, see "Issues in focus"). With costs for natural gas-fired generation rising in the Reference case and uncertainty about future regulation of GHG emissions, the economics of keeping existing nuclear power plants in operation are favorable.

Solar photovoltaics and wind dominate renewable capacity growth

Figure 82. Renewable electricity generation capacity by energy source, including end-use capacity, 2011-2040 (gigawatts)



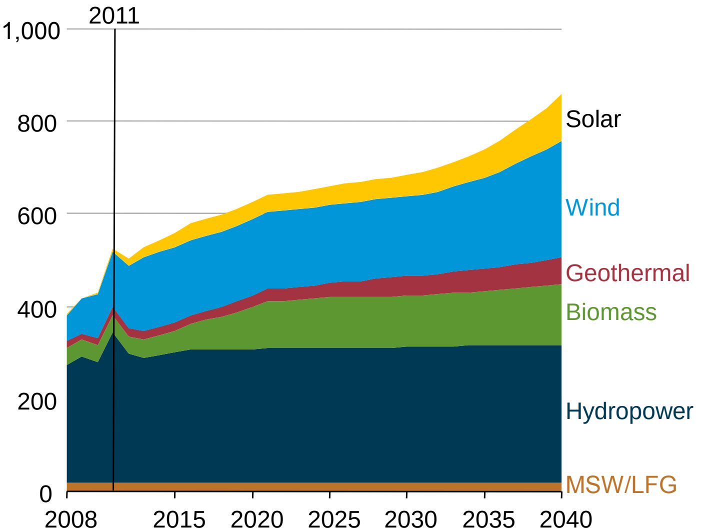
Renewable generating capacity accounts for nearly one-fifth of total generating capacity in 2040 in the *AEO2013* Reference case. Nearly all renewable capacity additions over the period consist of nonhydropower capacity, which grows by more than 150 percent from 2011 to 2040 (Figure 82).

Solar generation capacity leads renewable capacity growth, increasing by more than 1,000 percent, or 46 gigawatts, from 2011 to 2040. Wind capacity follows closely, accounting for an additional 42 gigawatts of new renewable capacity by 2040. Nonetheless, wind continues to be the leading source of nonhydropower renewable capacity in 2040, given its relatively high initial capacity in 2011, after a decade of exponential growth resulting from the availability of production tax credits and other incentives. Although geothermal and dedicated biomass generation capacity do not increase on the same scale as wind and solar (contributing an additional 5 gigawatts and 7 gigawatts, respectively, over the projection period), biomass capacity nearly doubles and geothermal capacity more than triples over the same period.

Renewable capacity additions are supported by state RPS, the federal renewable fuels standard, and federal tax credits. Near-term growth is strong as developers build capacity to qualify for tax credits that expire at the end of 2012, 2013, and 2016. After 2016, capacity growth through 2030 is minimal, given relatively slower growth in electricity demand, low natural gas prices, and the stagnation or expiration of the state and federal policies that support renewable capacity additions. As the need for new generation capacity increases, however, and as renewables become increasingly cost-competitive in selected regions, growth in nonhydropower renewable generation capacity rebounds during the final decade of the Reference case projection from 2030 to 2040.

Solar, wind, and biomass lead growth in renewable generation, hydropower remains flat

Figure 83. Renewable electricity generation by type, including end-use generation, 2008-2040 (billion kilowatthours)

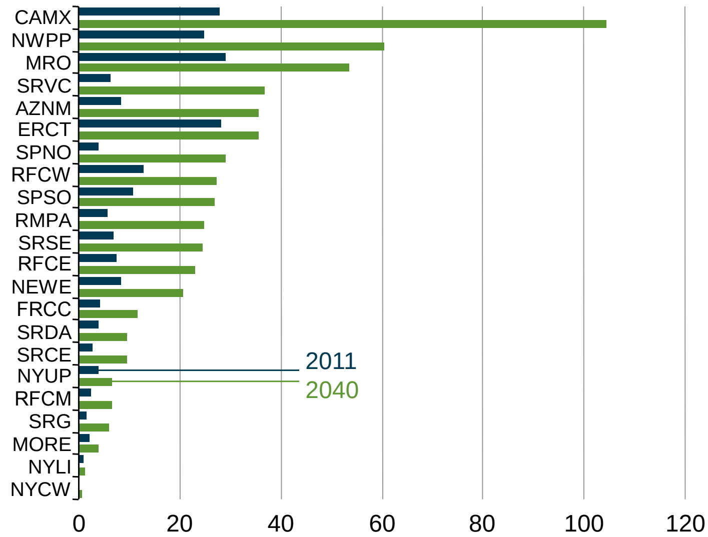


In the *AEO2013* Reference case, renewable generation increases from 524 billion kilowatthours in 2011 to 858 billion kilowatthours in 2040, growing by an average of 1.7 percent per year (Figure 83). Wind, solar, and biomass account for most of the growth. The increase in wind-powered generation from 2011 to 2040, at 134 billion kilowatthours, or 2.6 percent per year, represents the largest absolute increase in renewable generation. Generation from solar energy grows by 92 billion kilowatthours over the same period, representing the highest annual average growth at 9.8 percent per year. Biomass increases by 95 billion kilowatthours over the projection period, for an average annual increase of 4.5 percent.

Hydropower production drops in 2012, from 325 billion kilowatthours in 2011, as existing plants are assumed to continue operating at their long-term average production levels. Even with little growth in capacity, hydropower remains the leading source of renewable generation throughout the projection. Although total wind capacity exceeds hydropower capacity in 2040, wind generators typically operate at much lower capacity factors, and their total generation is lower. Biomass is the third-largest source of renewable generation throughout the projection, with rapid growth particularly in the first decade of the period, reaching 102 billion kilowatthours in 2021 from 37 billion kilowatthours in 2011. The strong growth is a result primarily of increased penetration of co-firing technology in the electric power sector, encouraged by state-level policies and increasing cost-competitiveness with coal in parts of the Southeast.

State renewable portfolio standards increase renewable electricity generation

Figure 84. Regional nonhydropower renewable electricity generation, including end-use generation, 2011 and 2040 (billion kilowatthours)



Regional growth in nonhydroelectric renewable electricity generation is based largely on three factors: availability of renewable energy resources, cost competitiveness with fossil fuel technologies, and the existence of state RPS programs that require the use of renewable generation. After a period of robust RPS enactments in several states, the past few years have been relatively quiet in terms of state program expansions.

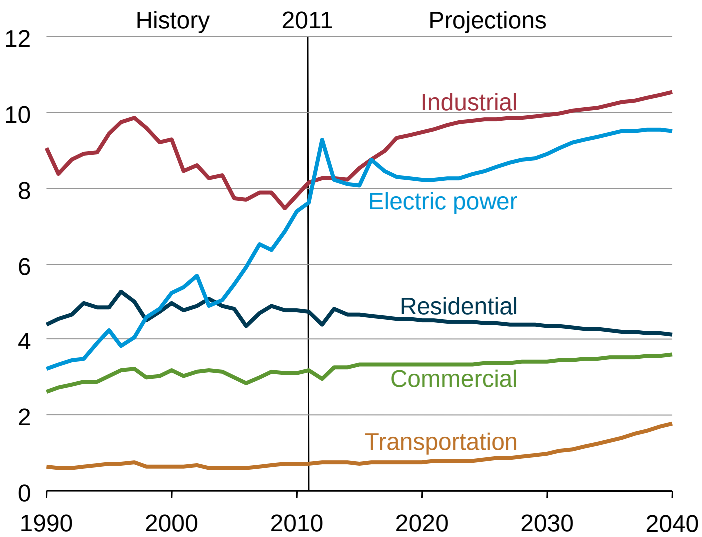
In the *AEO2013* Reference case, the highest level of nonhydroelectric renewable generation in 2040, at 104 billion kilowatthours, occurs in the WECC California (CAMX) region (Figure 84), whose area approximates the California state boundaries. (For a map of the electricity regions and a definition of the acronyms, see Appendix F.) The three largest sources of nonhydro-electric renewable generation in 2040 in that region are geothermal, solar, and wind energy. The region encompassing the Pacific Northwest has the most renewable generation in the United States when hydroelectric is included, which is the source of most of the region's renewable electricity generation.

State RPS programs heavily influence the growth of solar capacity in the eastern states. A prime example is the Reliability First Corporation/East (RFCE) region, where 7.5 billion kilowatthours of electricity is generated from solar resources in 2040, mostly from end-use capacity. The RFCE region is not known for a strong solar resource base, and the projected installations are in response to the federal tax credits, state incentives, and solar energy requirements embedded in state RPS programs. The CAMX region has the highest total for solar generation in 2040 at 36 billion kilowatthours, including 10 billion kilowatthours of generation from end-use solar capacity.

Natural gas consumption

Industrial and electric power sectors lead U.S. growth in natural gas consumption

Figure 85. Natural gas consumption by sector, 1990-2040 (trillion cubic feet)



U.S. total natural gas consumption grows from 24.4 trillion cubic feet in 2011 to 29.5 trillion cubic feet in 2040 in the *AEO2013* Reference case. Natural gas use increases in all the end-use sectors except residential (Figure 85), where consumption declines as a result of improvements in appliance efficiency and falling demand for space heating, attributable in part to population shifts to warmer regions of the country.

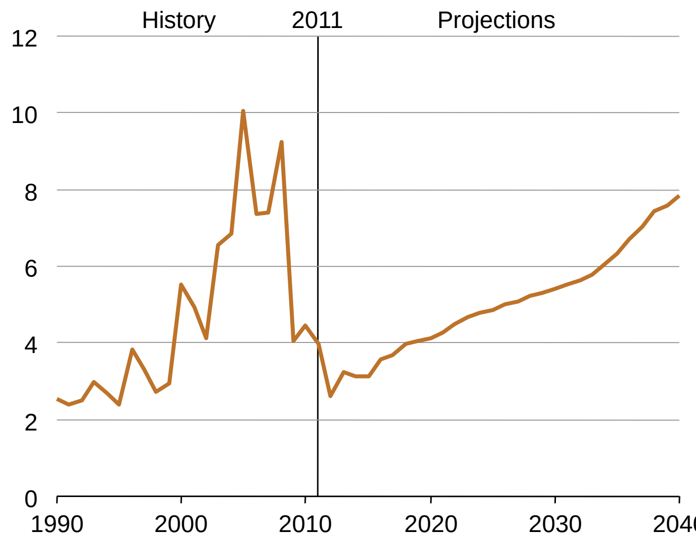
Despite falling early in the projection period from a spike in 2012, which resulted from very low natural gas prices relative to coal, consumption of natural gas for power generation increases by an average of 0.8 percent per year, with more natural gas used for electricity production as relatively low prices make natural gas more competitive with coal. Over the projection period, the natural gas share of total power generation grows, while the coal share declines.

Natural gas consumption in the industrial sector increases by an average of 0.5 percent per year from 2011 to 2040. This includes 0.7 trillion cubic feet of natural gas used in GTL, which is largely consumed in the transportation sector. Industrial output grows as the energy-intensive industries take advantage of relatively low natural gas prices, particularly through 2025. After 2025, growth in the sector slows in response to rising prices and increased international competition.

Although vehicle uses currently account for only a small part of total U.S. natural gas consumption, the projected percentage growth in natural gas demand by vehicles is the largest percentage growth in the projection. With incentives and low natural gas prices leading to increased demand for natural gas as a fuel for HDVs, particularly after 2025, consumption in vehicles increases from about 40 billion cubic feet in 2011 to just over 1 trillion cubic feet in 2040.

Natural gas prices rise with an expected increase in production costs after 2015

Figure 86. Annual average Henry Hub spot natural gas prices, 1990-2040 (2011 dollars per million Btu)



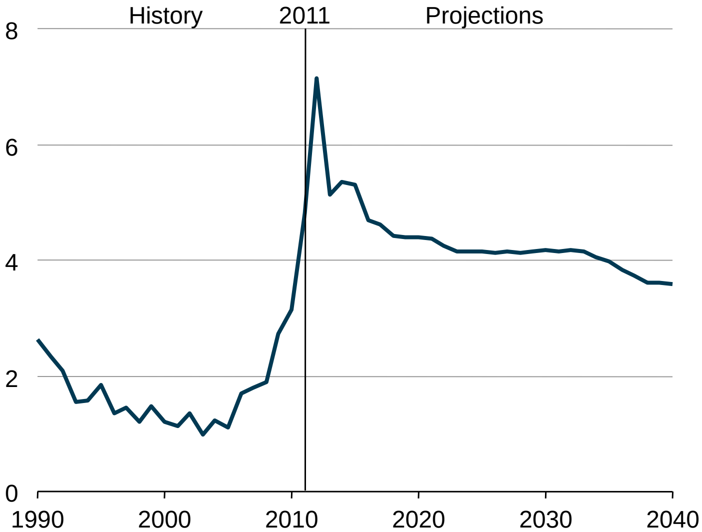
U.S. natural gas prices have remained relatively low over the past several years as a result of abundant domestic supply and efficient methods of production. However, the cost of developing new incremental production needed to support continued growth in natural gas consumption and exports rises gradually in the *AEO2013* Reference case, leading to an increase in the Henry Hub spot price. Henry Hub spot prices for natural gas increase by an average of about 2.4 percent per year, to $7.83 per million Btu (2011 dollars) in 2040 (Figure 86).

As of January 1, 2011, total proved and unproved U.S. natural gas resources (total recoverable resources) were estimated to total 2,327 trillion cubic feet. Over time, however, the depletion of resources in inexpensive areas leads producers to basins where recovery of the gas is more difficult and more expensive, causing the cost of production to rise gradually.

In the Reference case, natural gas prices remain low at the beginning of the projection period, as producers continue to extract natural gas resources from the most productive and inexpensive areas. Drilling activity remains robust despite the relatively low prices (below $4 per million Btu), particularly as producers extract natural gas from areas with high contents of NGL or oil. Prices begin to rise after 2015, and they continue rising in the projection through 2040.

Energy from natural gas remains far less expensive than energy from oil through 2040

Figure 87. Ratio of Brent crude oil price to Henry Hub spot natural gas price in energy-equivalent terms, 1990-2040



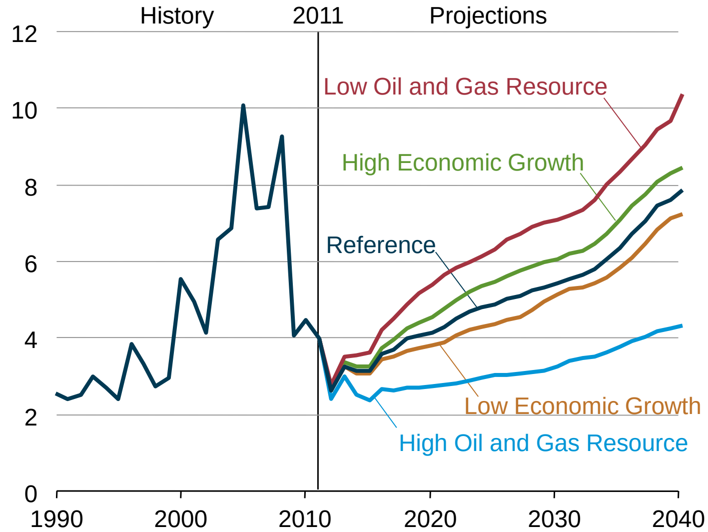
The ratio of oil prices to natural gas prices is defined in terms of the Brent crude oil price and the Henry Hub spot natural gas price on an energy-equivalent basis. U.S. natural gas prices are determined largely on a regional basis, in response to supply and demand conditions in North America. Oil prices are more responsive to global supply and demand. A 1:1 ratio indicates that crude oil and natural gas cost the same in terms of energy content. On that basis, crude oil remains far more expensive than natural gas through 2040 (Figure 87), but the difference in the costs of the two fuels narrows over time.

With rising demand and production costs, both crude oil and natural gas prices increase through 2040; however, the oil price rises more slowly than the natural gas price, bringing the oil-to-gas price ratio down from its 2012 level. Low natural gas prices, the result of abundant domestic supply and weak winter demand, combined with high oil prices, caused a sharp rise in the oil-to-gas price ratio in 2012.

Natural gas prices nearly double in the *AEO2013* Reference case, from $3.98 per million Btu in 2011 to $7.83 in 2040 (2011 dollars), and oil prices increase by about 50 percent, to $28.05 per million Btu in 2040. Over the entire period, the ratio remains well above the levels of the two previous decades. Oil and natural gas prices were more strongly aligned until about 2006, and the ratio of oil prices to natural gas prices was lower. Since 2006, however, natural gas prices have fallen as a result of abundant domestic supplies and production. In contrast, oil prices have increased and remained relatively high as global demand has increased over the past several years.

Natural gas prices depend on economic growth and resource recovery rates among other factors

Figure 88. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2011 dollars per million Btu)



Future levels of natural gas prices depend on many factors, including macroeconomic growth rates and expected rates of resource recovery from natural gas wells. Higher rates of economic growth lead to increased consumption of natural gas (primarily in response to higher levels of housing starts, commercial floorspace, and industrial output), causing more rapid depletion of natural gas resources and a more rapid increase in the cost of developing new production, which push natural gas prices higher. The converse is true in the Low Economic Growth case (Figure 88).

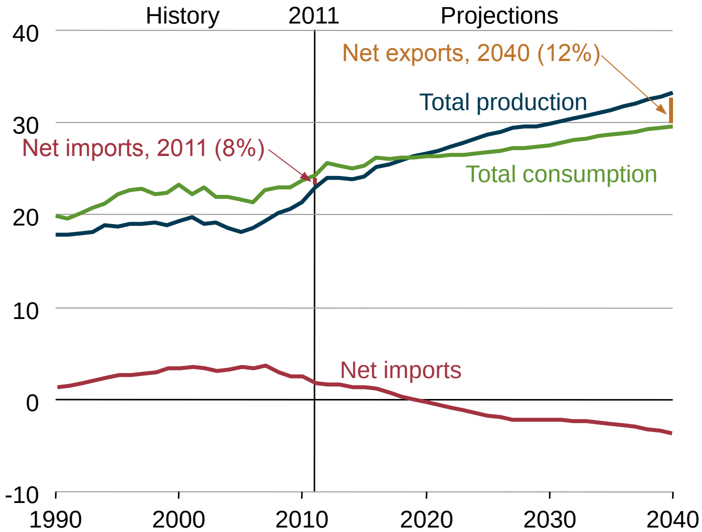
A lower rate of recovery from oil and gas wells implies higher costs per unit and higher prices. A higher rate of recovery implies lower costs per unit and lower prices. In comparison with the Reference case, the Low Oil and Gas Resource case assumes lower estimated ultimate recovery (EUR) from each shale well or tight well. The High Oil and Gas Resource case represents a more extreme case, with higher estimates for recoverable crude oil and natural gas resources in tight wells and shale formations and for offshore resources in the lower 48 states and Alaska.

In both cases, there are mitigating effects that dampen the initial price response from the demand or supply shift. For example, lower natural gas prices lead to an increase in natural gas exports, which places some upward pressure on natural gas prices. In addition, lower prices are likely to lead to less drilling for natural gas and lower production potential, placing some upward pressure on natural gas prices.

Natural gas production

With production outpacing consumption, U.S. exports of natural gas exceed imports

Figure 89. Total U.S. natural gas production, consumption, and net imports, 1990-2040 (trillion cubic feet)



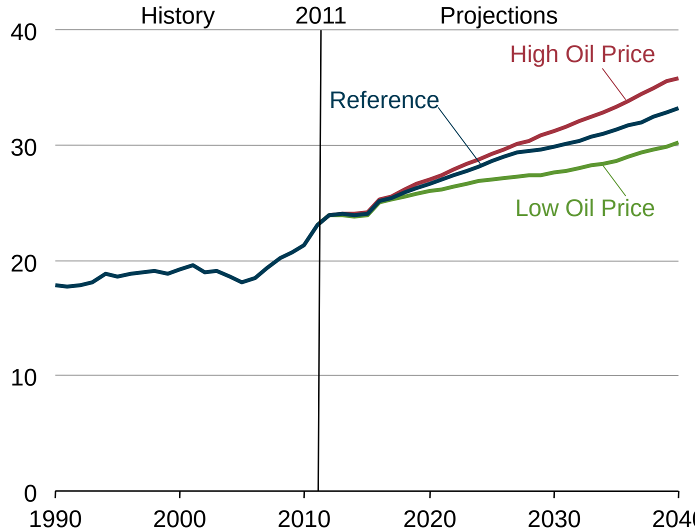
The United States consumed more natural gas than it produced in 2011, with net imports of almost 2 trillion cubic feet. As domestic supply has increased, however, natural gas prices have declined, making the United States a less attractive market and reducing U.S. imports. Conversely, lower prices have made purchases of U.S. natural gas more attractive, increasing exports. In the *AEO2013* Reference case, the United States becomes a net exporter of natural gas by 2020 (Figure 89).

Production growth, led by increased development of shale gas resources, outpaces consumption growth in the Reference case—a pattern that continues through 2040. As a result, exports continue to grow at a rate of about 17.7 percent per year from 2020 to 2040. Net exports in 2020 are less than 1 percent of total consumption; in 2040 they are 12 percent of consumption.

U.S. natural gas production increases by about 1 percent per year from 2011 to 2040 in the Reference case, meeting domestic demand while also allowing for more exports. The prospects for future exports are highly uncertain, however, depending on many factors that are difficult to anticipate, such as the development of new production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic.

U.S. natural gas production is affected by oil prices through consumption and exports

Figure 90. Total U.S. natural gas production in three oil price cases, 1990-2040 (trillion cubic feet per year)



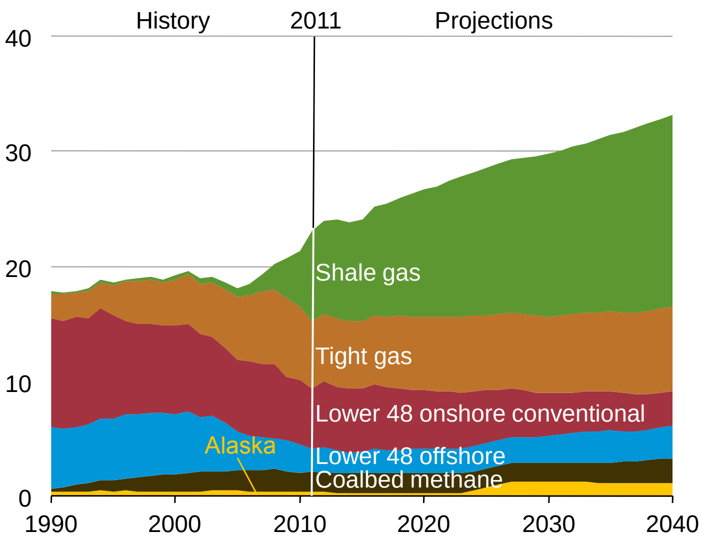
U.S. natural gas production is affected by crude oil prices primarily through changes in natural gas consumption and exports. Across the *AEO2013* oil price cases, the largest changes in natural gas use occur in natural gas converted into liquid fuels via GTL, directly consumed in transportation as CNG or LNG, and exported as LNG. Because world LNG prices are directly affected by crude oil prices, depending on regional market conditions, crude oil prices are important to the market value of LNG exported from the United States.

The profitability of using natural gas as a transportation fuel, or for exporting LNG, depends largely on the price differential between crude oil and natural gas. The greater the difference between crude oil and natural gas prices, the greater the incentive to use natural gas. For example, in the Low Oil Price case, average oil prices are about $7.80 per million Btu higher than natural gas prices from 2012 through 2040—a relatively low price differential that leads to virtually no use of natural gas for transportation and very little for LNG exports. In the High Oil Price case, the average price difference is about $24.30 per million Btu from 2012 through 2040, providing the incentives necessary to promote natural gas use in transportation applications and for export.

Across the price cases, total natural gas production varies by 5.6 trillion cubic feet in 2040 (Figure 90). Changes in LNG exports account for 3.6 trillion cubic feet of the difference. Direct consumption of natural gas for transportation varies by 2.1 trillion cubic feet between the two cases, and consumption for GTL production varies by 1.1 trillion cubic feet. Across the price cases, as natural gas production rises, so do natural gas prices; and as natural gas prices rise, consumption in the other end-use sectors falls by as much as 2.5 trillion cubic feet.

Shale gas provides the largest source of growth in U.S. natural gas supply

Figure 91. Natural gas production by source, 1990-2040 (trillion cubic feet)



The 44-percent increase in total natural gas production from 2011 through 2040 in the *AEO2013* Reference case results from the increased development of shale gas, tight gas, and coalbed methane resources (Figure 91). Shale gas production, which grows by 113 percent from 2011 to 2040, is the greatest contributor to natural gas production growth. Its share of total production increases from 34 percent in 2011 to 50 percent in 2040. Tight gas and coalbed methane production also increase, by 25 percent and 24 percent, respectively, from 2011 to 2040, even as their shares of total production decline slightly. The growth in coalbed methane production is not realized until after 2035, when natural gas prices and demand levels are high enough to spur more drilling.

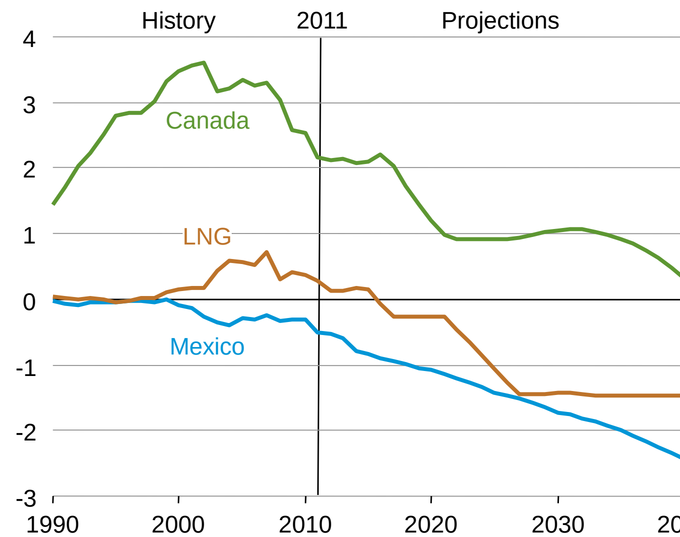
Offshore natural gas production declines by 0.3 trillion cubic feet from 2011 through 2014, as offshore exploration and development activities are directed toward oil-prone areas in the Gulf of Mexico. After 2014, offshore natural gas production recovers as prices rise, growing to 2.8 trillion cubic feet in 2040. As a result, from 2011 to 2040, offshore natural gas production increases by 35 percent.

Alaska natural gas production also increases in the Reference case with the advent of Alaska LNG exports to overseas customers beginning in 2024 and growing to 0.8 trillion cubic feet per year (2.2 billion cubic feet per day) in 2027. In 2040, Alaska natural gas production totals 1.2 trillion cubic feet.

Although total U.S. natural gas production rises throughout the projection, onshore nonassociated conventional production declines from 3.6 trillion cubic feet in 2011 to 1.9 trillion cubic feet in 2040, when it accounts for only about 6 percent of total domestic production, down from 16 percent in 2011.

Pipeline exports increase as Canadian imports fall and exports to Mexico rise

Figure 92. U.S. net imports of natural gas by source, 1990-2040 (trillion cubic feet)



With relatively low natural gas prices in the *AEO2013* Reference case, the United States becomes a net exporter of natural gas in 2020, and net exports grow to 3.6 trillion cubic feet in 2040 (Figure 92). Most of the projected growth in U.S. exports consists of pipeline exports to Mexico, which increase steadily over the projection period, as increasing volumes of imported natural gas from the United States fill the growing gap between Mexico's production and consumption. Exports to Mexico increase from 0.5 trillion cubic feet in 2011 to 2.4 trillion cubic feet in 2040.

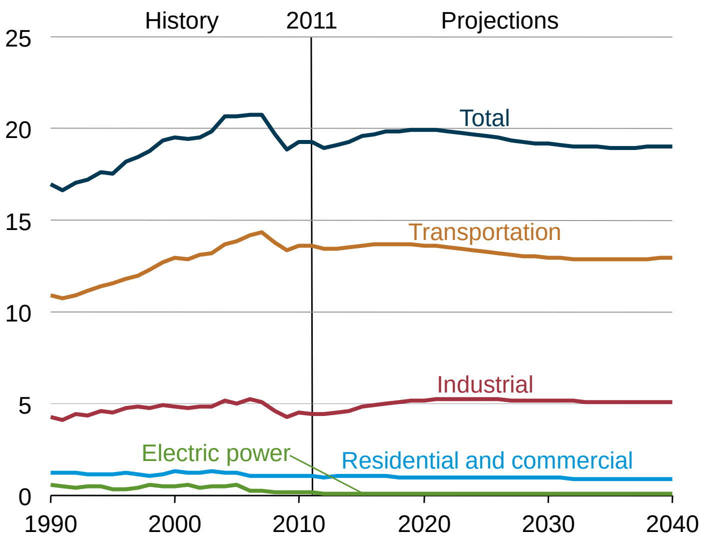
U.S. exports of domestically sourced LNG (excluding existing exports from the Kenai facility in Alaska, which fall to zero in 2013) begin in 2016 and rise to a level of 1.6 trillion cubic feet per year in 2027. One-half of the projected increase in U.S. exports of LNG originate in the Lower 48 states and the other half from Alaska. Continued low levels of LNG imports through the projection period position the United States as a net exporter of LNG by 2016. In general, future U.S. exports of LNG depend on a number of factors that are difficult to anticipate, including the speed and extent of price convergence in global natural gas markets, the extent to which natural gas competes with oil in domestic and international markets, and the pace of natural gas supply growth outside the United States.

Net natural gas imports from Canada decline sharply from 2016 to 2022, then stabilize somewhat before dropping off again in the final years of the projection, as continued growth in domestic production mitigates the need for imports. Even as overall consumption exceeds supply in the United States, some natural gas imports from Canada continue, based on regional supply and demand conditions.

Petroleum and other liquids consumption

Petroleum and other liquids consumption outside industrial sector is stagnant or declines

Figure 93. Consumption of petroleum and other liquids by sector, 1990-2040 (million barrels per day)



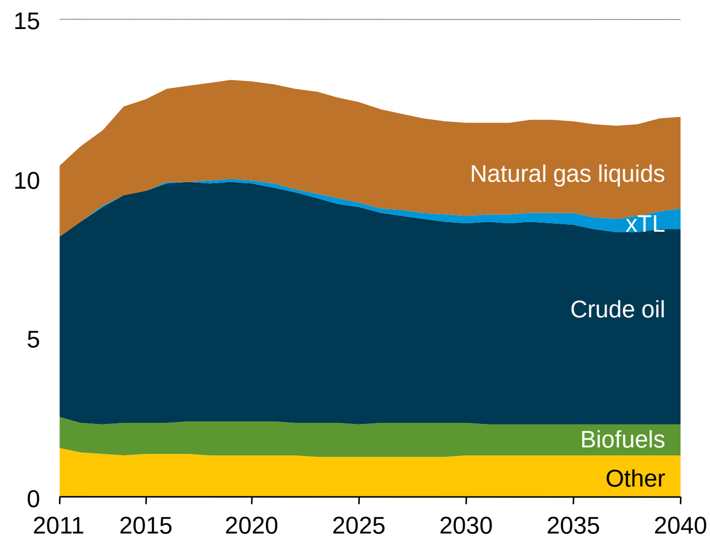
Consumption of petroleum and other liquids peaks at 19.8 million barrels per day in 2019 in the *AEO2013* Reference case and then falls to 18.9 million barrels per day in 2040 (Figure 93). The transportation sector accounts for the largest share of total consumption throughout the projection, although its share falls to 68 percent in 2040 from 72 percent in 2012 as a result of improvements in vehicle efficiency following the incorporation of CAFE standards for both LDVs and HDVs. Consumption of petroleum and other liquids increases in the industrial sector, by 0.6 million barrels per day from 2011 to 2040, but decreases in all the other end-use sectors.

Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, supplemented by biofuels and natural gas. Motor gasoline consumption drops by approximately 1.6 million barrels per day from 2011 to 2040 in the Reference case, while diesel fuel consumption increases from 3.5 million barrels per day in 2011 to 4.3 million in 2040, primarily for use in heavy-duty vehicles. At the same time, natural gas use in heavy-duty vehicles displaces 0.7 million barrels per day of petroleum-based motor fuel in 2040, most of which is diesel.

An increase in consumption of biodiesel and next-generation biofuels [*136*], totaling about 0.4 million barrels per day from 2011 to 2040, is attributable to the EISA2007 RFS mandates. The relative competitiveness of CTL and GTL fuels improves over the projection period as petroleum prices rise. In 2040, CTL and GTL together supply 0.3 million barrels per day of non-petroleum liquids. Both ethanol blending into gasoline and E85 consumption are essentially flat from 2011 through 2040, as a result of declining gasoline consumption and limited penetration of FFVs.

Crude oil leads initial growth in liquids supply, next-generation liquids grow after 2020

Figure 94. U.S. production of petroleum and other liquids by source, 2011-2040 (million barrels per day)



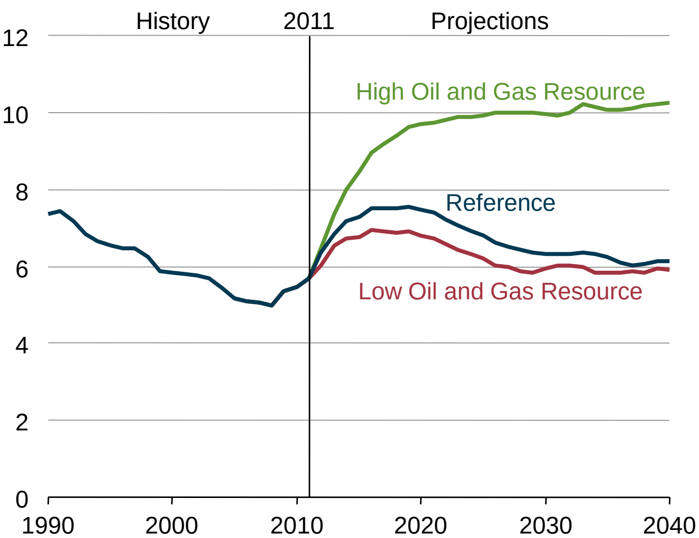
In the *AEO2013* Reference case, total production of petroleum and other liquids grows rapidly in the first decade and then slows in the later years before 2040 (Figure 94). Liquids production increases from 10.4 million barrels per day in 2011 to 13.1 million barrels per day in 2019 primarily as a result of growth in onshore production of crude oil and NGL from tight oil formations (including shale plays).

After 2019, total U.S. production of petroleum and other liquids declines, to 12.0 million barrels per day in 2040, as crude oil production from tight oil plays levels off when less-productive or less-profitable areas are developed. The crude oil share of total domestic liquids production declines to 51 percent in 2040 from a peak of 59 percent in 2016. NGL production also declines, to 2.9 million barrels per day in 2040 from a peak of 3.2 million barrels per day in 2024.

Domestic ethanol production remains relatively flat throughout the projection, as consumption of motor gasoline decreases and the penetration of ethanol in the gasoline pool is slowed by the limited availability of FFVs and retrofitted filling stations. Total biofuel production increases by 0.4 million barrels per day in the projection, as drop-in fuels from biomass enter the market. Other emerging technologies capable of producing liquids—such as xTL [*137*], which includes CTL and GTL technologies—also become economical as more plants are built. In 2040, liquids production from xTL plants totals 0.3 million barrels per day. Investment in xTL technologies is slowed somewhat by high capital costs and the risk that xTL liquids production will not remain price-competitive with crude oil.

U.S. oil production rates depend on resource availability and advances in technology

Figure 95. Total U.S. crude oil production in three resource cases, 1990-2040 (million barrels per day)



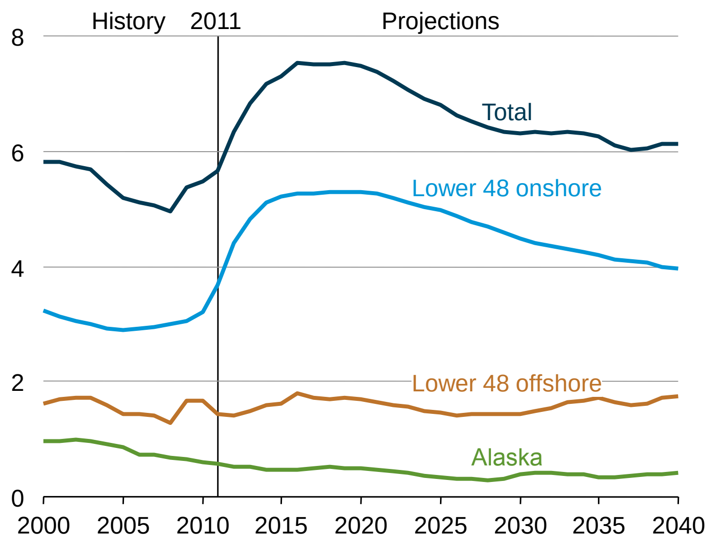
The outlook for domestic crude oil production depends on the production profiles of individual wells over time, the costs of drilling and operating those wells, and the revenues they generate (Figure 95). Every year, EIA reestimates initial production rates and production decline curves, which determine EUR per well and total technically recoverable resources. The underlying resource for the *AEO2013* Reference case is uncertain, particularly as exploration and development of tight oil continue to move into areas with little or no production history. Because many wells drilled in tight formations or shale formations using the latest technologies have less than two years of production history, the impacts of recent technology advances on the estimate of future recovery cannot be fully ascertained.

In the High Oil and Gas Resource case, domestic crude oil production continues to increase through the projection period, to more than 10 million barrels per day in 2040. This case includes: (1) higher estimates of onshore lower 48 tight oil, tight gas, and shale gas resources than in the Reference case, as a result of higher estimated ultimate recovery per well and closer well spacing as additional layers of low-permeability zones are identified and developed; (2) tight oil development in Alaska; and (3) higher estimates of offshore resources in Alaska and the lower 48 states, resulting in more and earlier development of those resources than in the Reference case.

The Low Oil and Gas Resource case considers the impacts of lower estimates of tight oil, tight gas, and shale gas resources than in the Reference case. These two alternative cases provide a framework for examining the impacts of higher and lower domestic supply on energy demand, imports, and prices.

Lower 48 onshore tight oil development spurs increase in U.S. crude oil production

Figure 96. Domestic crude oil production by source, 2000-2040 (million barrels per day)



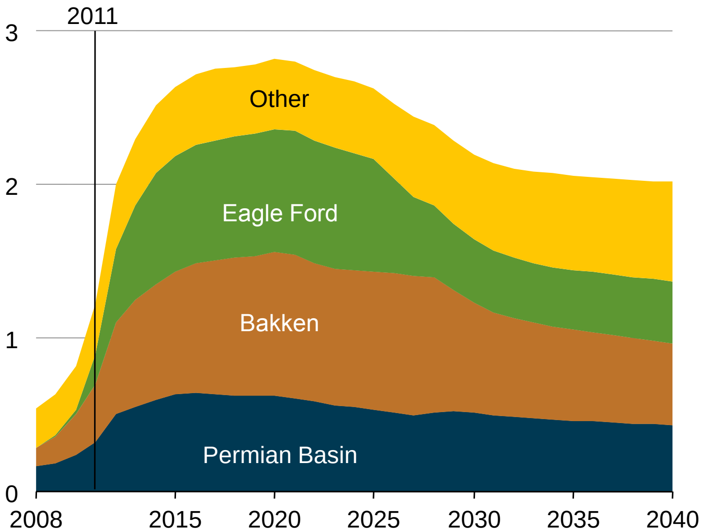
U.S. crude oil production rises through 2016 in the *AEO2013* Reference case, before leveling off at about 7.5 million barrels per day from 2016 through 2020—approximately 1.8 million barrels per day above 2011 volumes (Figure 96). Growth in lower 48 onshore crude oil production results primarily from continued development of tight oil resources, mostly in the Bakken, Eagle Ford, and Permian Basin formations. Tight oil production reaches 2.8 million barrels per day in 2020 and then declines to about 2.0 million barrels per day in 2040, still higher than 2011 levels, as high-productivity sweet spots are depleted. There is uncertainty about the expected peak level of tight oil production, because ongoing exploration, appraisal, and development programs expand operators' knowledge about producing reservoirs and could result in the identification of additional tight oil resources.

Crude oil production using carbon dioxide-enhanced oil recovery (CO_2-EOR) increases appreciably after about 2020, when oil prices rise as output from the more profitable tight oil deposits begins declining, and affordable anthropogenic sources of carbon dioxide (CO_2) become available. Production plateaus at about 650,000 barrels per day from 2034 to 2040, when production is limited by reservoir quality and CO_2 availability. From 2012 through 2040, cumulative crude oil production from CO_2-EOR projects is 4.7 billion barrels.

Lower 48 offshore oil production varies between 1.4 and 1.8 million barrels per day over the projection period. Toward the end of the projection the pace of exploration and production activity quickens, and new large development projects, associated predominantly with discoveries in the deepwater and ultra-deepwater portions of the Gulf of Mexico, are brought on stream. New offshore oil production in the Alaska North Slope areas partially offsets the decline in production from North Slope onshore fields.

Tight oil formations account for a significant portion of total U.S. production

Figure 97. Total U.S. tight oil production by geologic formation, 2008-2040 (million barrels per day)



The term tight oil does not have a specific technical, scientific, or geologic definition. Tight oil is an industry convention that generally refers to oil produced from very-low-permeability [*138*] shale, sandstone, and carbonate formations. Some of these geologic formations have been producing low volumes of oil for many decades in limited portions of the formation.

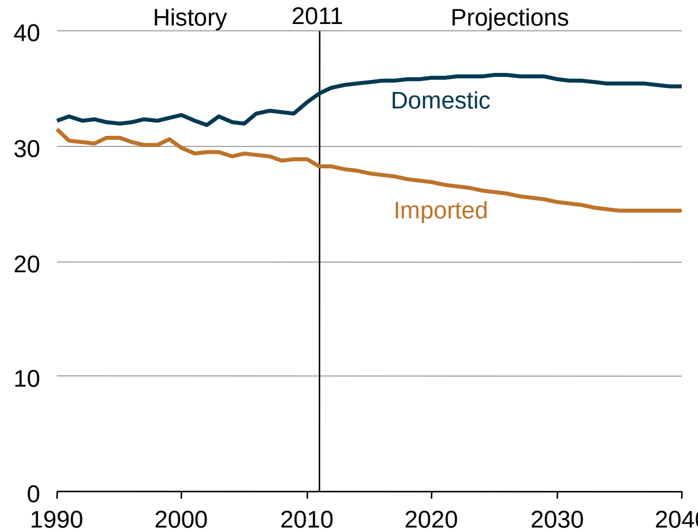
In the *AEO2013* Reference Case, about 25.3 billion barrels of tight oil are produced cumulatively from 2012 through 2040. The Bakken-Three Forks formations contribute 32 percent of this production, while the Eagle Ford and Permian Basin formations respectively account for 24 and 22 percent of the cumulative tight oil production. The remaining 22 percent of cumulative tight oil production comes from other formations, including but not limited to the Austin Chalk, Niobrara, Monterey, and Woodford formations. Permian Basin tight oil production comes primarily from the Spraberry, Wolfcamp, and Avalon/Bone Spring formations, which are listed here relative to their contribution to cumulative production.

After 2021, tight oil production declines in the *AEO2013* Reference case (Figure 97), as the depleted wells located in high-productivity areas are replaced by lower-productivity wells located elsewhere in the formations. In 2040, tight oil production is 2.0 million barrels per day, about 33 percent of total U.S. oil production. Because tight oil wells exhibit high initial production rates followed by slowly declining production rates in later years, production declines rather slowly at the end of the projection period.

Tight oil development is still at an early stage, and the outlook is highly uncertain. Alternative cases, including ones in which tight oil production is significantly above the Reference case projection, are examined in the "Issues in focus" section of this report (see "Petroleum import dependence in a range of cases").

Domestic production of tight oil leads to lower imports of light sweet crude oil

Figure 98. API gravity of U.S. domestic and imported crude oil supplies, 1990-2040 (degrees)



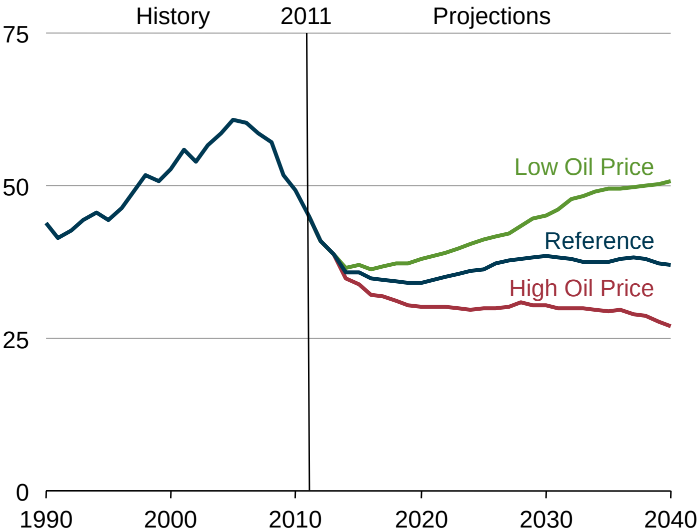
API gravity is a measure of the specific gravity, or relative density, of a liquid, as defined by the American Petroleum Institute (API). It is expressed in degrees, where a higher number indicates lower density. Refineries generally process a mix of crude oils with a range of API gravities in order to optimize refinery operations. Over the past 15 years, the API gravity of crude oil processed in U.S. refineries has averaged between 30 and 31 degrees. As U.S. refiners run more domestic light crude produced from tight formations, they need less imported light oil crude to maintain an optimal API gravity. With increasing U.S. production of light crude oil in the Reference case, the average API gravity of crude oil imports declines (Figure 98).

In the *AEO2013* Reference case, the trend toward increasing imports of heavier crude oils continues through 2035 before stabilizing [*139*]. The increase in demand for diesel fuel in the projection, from 3.5 to 4.3 million barrels per day, leads to an increase in distillate and gas oil hydrocracking capacity (which increases diesel production capability) from 1.6 to 3.0 million barrels per day from 2011 to 2040.

The large increase in domestic production of light crude oil and the increase in imports of heavier crude oils have prompted significant investments in crude midstream infrastructure, including pipelines that will bring higher quantities of light sweet crudes to petroleum refineries along the U.S. Gulf Coast. In addition, significant investments are being made to move crude oil to refineries by rail. The Reference case assumes that sufficient infrastructure investments will be made through 2040 to move both light and heavy crude oils.

Increasing U.S. supply results in decreasing net imports of petroleum and other liquids

Figure 99. Net import share of U.S. petroleum and other liquids consumption in three oil price cases, 1990-2040 (percent)



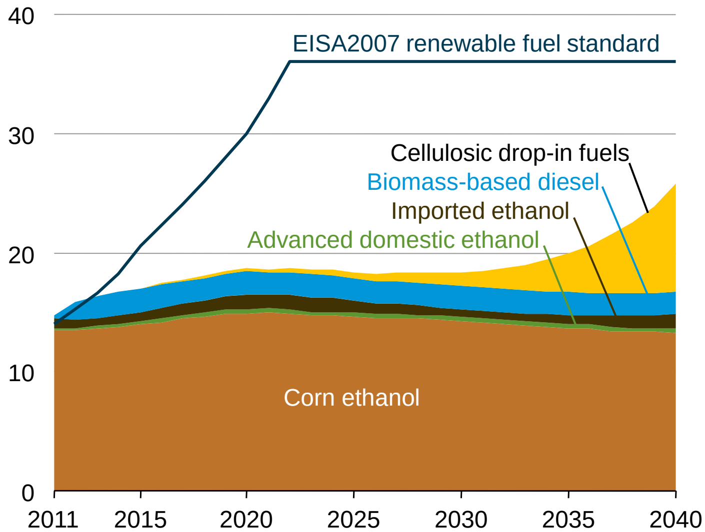
The net import share of U.S. petroleum and other liquids consumption (including crude oil, petroleum liquids, and liquids derived from nonpetroleum sources) grew steadily from the mid-1980s to 2005 but has fallen in every year since then. In the *AEO2013* Reference and High Oil Price cases, U.S. imports of petroleum and other liquids decline through 2020, while still providing approximately one-third of total U.S. supply. As a result of increased production of domestic petroleum, primarily from tight oil formations, and a moderation of demand growth with tightening fuel efficiency standards, the import share of total supply declines. Domestic production of crude oil from tight oil formations, primarily from the Williston, Western Gulf, and Permian basins, increases by about 1.5 million barrels per day from 2011 to 2016 in both the Reference and High Oil Price cases.

The net import share of U.S. petroleum and other liquids consumption, which fell from 60 percent in 2005 to 45 percent in 2011, continues to decline in the Reference case, with the net import share falling to 34 percent in 2019 before increasing to 37 percent in 2040 (Figure 99). In the High Oil Price case, the net import share falls to an even lower 27 percent in 2040. In the Low Oil Price case, the net import share remains relatively flat in the near term but rises to 51 percent in 2040, as domestic demand increases, and imports become less expensive than domestically produced crude oil.

As a result of increased domestic production and slow growth in consumption, the United States becomes a net exporter of petroleum products, with net exports in the Reference case increasing from 0.3 million barrels per day in 2011 to 0.7 million barrels per day in 2040. In the High Oil Price case, net exports of petroleum products increase to 1.2 million barrels per day in 2040.

U.S. consumption of cellulosic biofuels falls short of EISA2007 Renewable Fuels Standard target

Figure 100. EISA2007 RFS credits earned in selected years, 2011-2040 (billion credits)



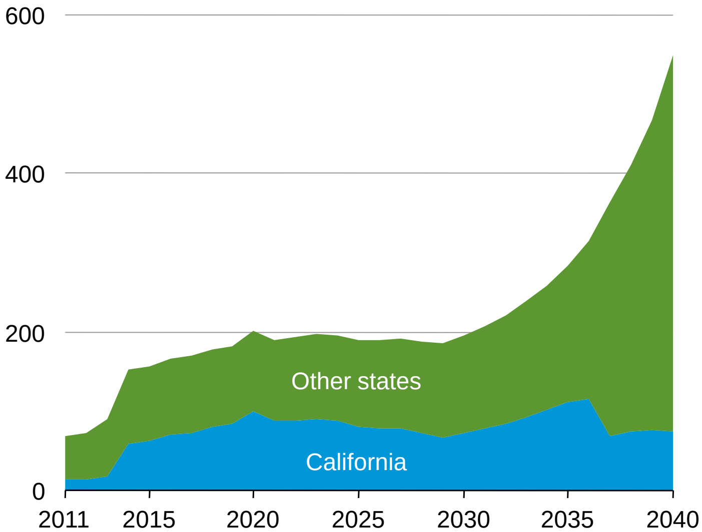
Biofuel consumption grows in the *AEO2013* Reference case but falls well short of the EISA2007 RFS target [*140*] of 36 billion gallons ethanol equivalent in 2022 (Figure 100), largely because of a decline in gasoline consumption as a result of newly enacted CAFE standards and updated expectations for sales of vehicles capable of using E85. From 2011 to 2022, demand for motor gasoline ethanol blends (E10 and E15) falls from 8.7 million barrels to 8.1 million barrels per day.

Because the current and projected vehicle fleets are not equipped to use ethanol's increased octane relative to gasoline, they cannot offset its lower energy density. As a result, the wholesale price of ethanol does not exceed two-thirds of the wholesale gasoline price. This reflects the energy-equivalent value of ethanol and would be the equilibrium price in periods with significant market penetration of blends with high ethanol content, such as E85. The RFS program does not provide sufficient incentives to promote significant new ethanol capacity in this pricing environment. Also during the projection period, consumption of biomass-based diesel levels off in the Reference case after growing to meet the current RFS target of 1.9 billion gallons ethanol equivalent in 2013.

Ethanol consumption falls from 16.4 billion gallons in 2022 to 14.9 billion gallons in 2040 in the *AEO2013* Reference case, as gasoline demand continues to drop and E85 consumption levels off. However, domestic consumption of drop-in cellulosic biofuels grows from 0.3 billion gallons to 9.0 billion gallons ethanol equivalent per year from 2011 to 2040, as rising oil prices lead to price increases for diesel fuel, heating oil, and jet fuel, while production costs for biofuel technologies fall.

Renewable Fuel Standard and California Low Carbon Fuel Standard boost the use of new fuels

Figure 101. Consumption of advanced renewable fuels, 2011-2040 (thousand barrels per day)



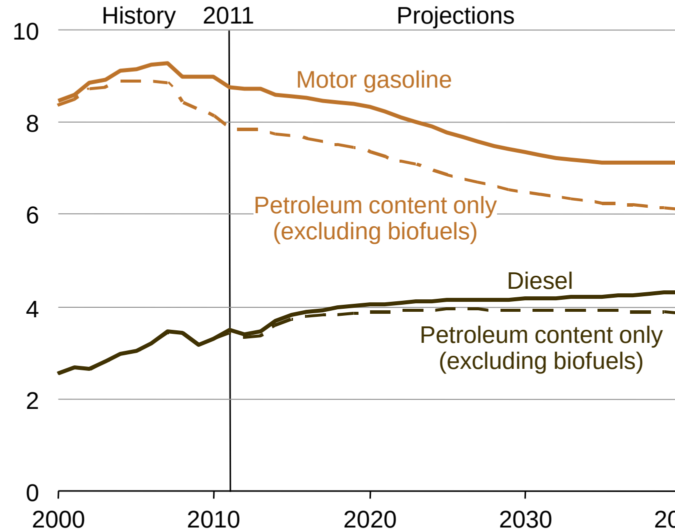
In response to the RFS implemented nationwide and the California Low Carbon Fuel Standard (LCFS), consumption of advanced biofuels increases in the *AEO2013* Reference case (Figure 101). As defined in the RFS, the advanced renewable fuels category consists of fuels that achieve a 50-percent reduction in life-cycle GHG emissions (including indirect changes in land use). The advanced fuel category includes ethanol produced from sugar cane (but not from corn starch), biodiesel, renewable diesel, and cellulosic biofuels [*141*]. California uses a large fraction of the total advanced renewable fuel pool in the early years of the projection.

Under the California LCFS, each fuel is considered individually according to its carbon intensity relative to the LCFS target. In general, fuels that qualify as advanced renewable fuels under the RFS have low carbon intensities for the purposes of the California LCFS, but the reverse is not always true.

Starting about 2030, production of cellulosic drop-in biofuels ramps up in California and other states. Outside California, production and consumption of cellulosic biofuels increases rapidly enough to cause a decline in California's fraction of the total advanced biofuels market. Starting in about 2035, corn ethanol with low carbon intensity begins to displace imported sugar cane ethanol in California.

Efficiency standards shift consumption from motor gasoline to diesel fuel

Figure 102. U.S. motor gasoline and diesel fuel consumption, 2000-2040 (million barrels per day)



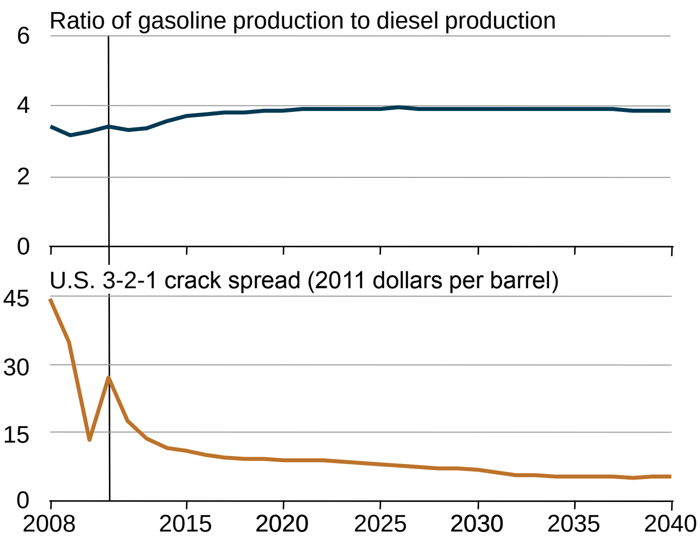
Based on NHTSA estimates, more stringent efficiency standards for LDVs will require new LDVs to average approximately 49 mpg in 2025, in addition to regulations requiring increased use of ethanol. The combination contributes to a decline in consumption of motor gasoline and an increase in consumption of diesel fuel and ethanol in the *AEO2013* Reference case. Motor gasoline consumption falls despite an increase in VMT by LDVs over the projection period.

The decrease in gasoline consumption, combined with growth in diesel consumption, leads to a shift in refinery outputs and investments. Motor gasoline consumption and diesel fuel consumption trend in opposite directions in the Reference case: consumption of diesel fuel increases by approximately 0.8 million barrels per day from 2011 to 2040, while finished motor gasoline consumption falls by 1.6 million barrels per day (Figure 102). Although some smaller and less-integrated refineries begin to idle capacity as a result of higher costs, new refinery projects focus on shifting production from gasoline to distillate fuels to meet growing demand for diesel.

In the Reference case, as a result of refinery economics and slower growth in domestic demand, no new petroleum refinery capacity expansions are built during the projection period besides those already under construction. Further, approximately 200,000 barrels per day of capacity is retired, beginning in 2012. In addition to meeting domestic demand, refineries continue exporting finished products to international markets throughout the projection period. From 2014 to 2017 gross exports of finished products increase to more than 3.0 million barrels per day for the first time, and they remain near that level through 2040. Further, the United States, which became a net exporter of finished products in 2011, remains a net exporter through 2040 in the Reference case.

Shifts in demand for liquid fuels change petroleum refinery yields and crack spreads

Figure 103. U.S. refinery gasoline-to-diesel production ratio and crack spread, 2008-2040

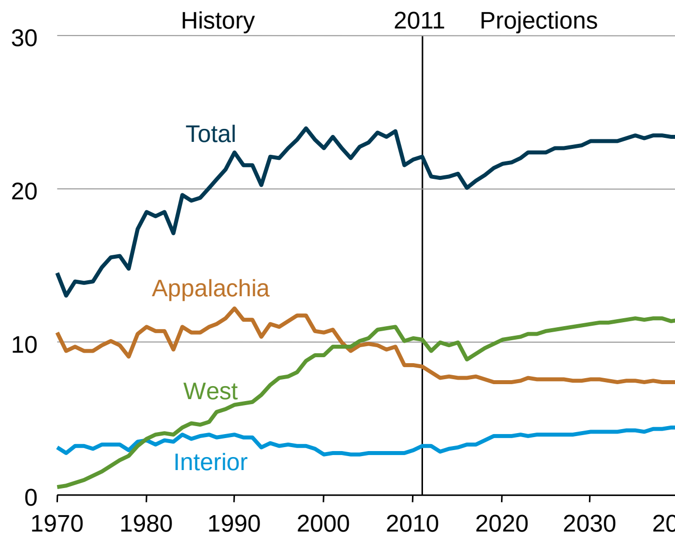


The transition to lower gasoline and higher diesel production has a significant effect on petroleum refinery operations. In the *AEO2013* Reference case, the ratio of gasoline to diesel production at petroleum refineries declines from 2.3 in 2012 to 1.6 after 2035 (Figure 103). In response to the drop in gasoline demand, refinery utilization of fluid catalytic cracking (FCC) units drops from 83 percent in 2011 to about 62 percent in 2040. In contrast, with diesel production increasing, installed distillate and gas oil hydrocracking capacity grows from about 1.8 million barrels per day in 2012 to 3.0 million barrels per day in 2040. The increase in installed hydrocracking capacity implies a shifting of FCC feeds to hydrocrackers in order to maximize diesel production.

Refinery profitability is a function of crude input costs, processing costs, and market prices for the end products. Profitability often is estimated from the crack spread, which is the difference between the price of crude oil and the price of distilled products, typically gasoline and distillate fuel. The 3-2-1 crack spread estimates the profitability of processing 3 barrels of crude oil to produce 2 barrels of gasoline and 1 barrel of distillate. In the Reference case, the 3-2-1 crack spread (based on Brent) declines steadily from $17 per barrel (2011 dollars) in 2012 to about $5 per barrel in 2040. This represents a gross margin for the refinery, based on Brent crude prices and average gasoline and diesel prices in the United States. In the current environment, this gross margin would drop by the differential between the prices of Brent and Gulf Coast light crudes. To relate the gross margin to refinery profitability, operating costs for specific refineries would also have to be deducted. The decline in the 3-2-1 crack spread slows after 2016. As product demands shift, petroleum refineries may alter the ratio of gasoline to diesel production. A 5-3-2 crack spread would be more consistent with the 1.6 gasoline-to-diesel production ratio after 2035.

Early declines in coal production are followed by growth after 2016

Figure 104. Coal production by region, 1970-2040 (quadrillion Btu)



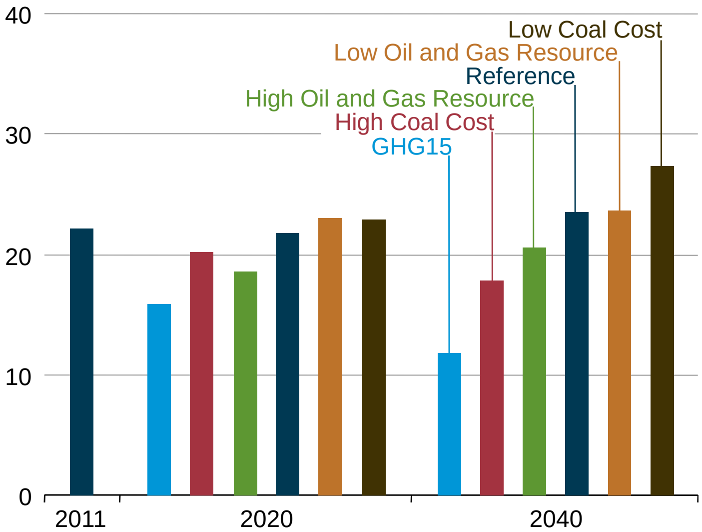
U.S. coal production largely follows the trend of domestic coal consumption, but increasingly it is influenced by coal exports. In the near term, the combination of relatively low natural gas prices and high coal prices, the lack of a strong recovery in electricity demand, and increasing generation of electricity from renewables suppress domestic coal consumption. In addition, new requirements to control emissions of mercury and acid gases result in the retirement of some coal-fired generating capacity, contributing to a near-term decline in coal demand. After 2016, coal production in the Reference case increases by an average of 0.6 percent per year through 2040 (Figure 104), as a result of growing coal exports and increasing use of coal in the electricity sector as electricity demand grows and natural gas prices rise.

On a regional basis, the Interior and Western regions show similar growth in production, while Appalachian output declines. Following some early setbacks, Western coal production increases steadily through 2035 before leveling off. Coal from the West satisfies much of the additional need for fuel at coal-fired power plants, and it is also boosted by increasing exports and production of synthetic liquids. Coal production in the Interior region, which has trended downward slightly since the early 1990s, reaches new highs in the *AEO2013* Reference case. Additional production from the region originates mostly from mines tapping into the substantial reserves of bituminous coal in Illinois, Indiana, and western Kentucky. Appalachian coal production declines substantially from current levels, as coal produced from the extensively mined, higher-cost reserves of Central Appalachia is supplanted by lower-cost coal from other regions. An expected increase in production from the northern part of the Appalachian basin moderates the overall decline.

Coal production

Outlook for U.S. coal production is affected by fuel price uncertainties

Figure 105. U.S. total coal production in six cases, 2011, 2020, and 2040 (quadrillion Btu)

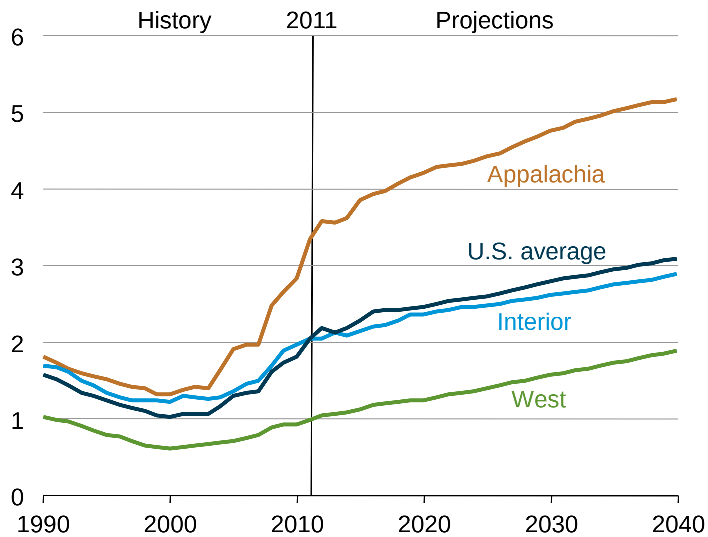


U.S. coal production varies across the *AEO2013* cases, reflecting the effects of different assumptions about the costs of producing and transporting coal, the outlook for natural gas prices, and possible controls on GHG emissions (Figure 105). In general, assumptions that reduce the competitiveness of coal versus natural gas result in less coal production: in the High Coal Cost case as a result of significantly higher estimated costs to mine and transport coal, and in the High Oil and Gas Resource case as a result of lower natural gas production costs than in the Reference case. Similarly, actions to reduce GHG emissions can reduce the competeviness of coal, because its high carbon content can translate into a price penalty, in the form of GHG fees, relative to other fuels. Conversely, lower coal prices in the Low Coal Cost case and higher natural gas prices in the Low Oil and Gas Resource case improve the competitiveness of coal and lead to higher levels of coal production.

Of the cases shown in Figure 105, the most substantial decline in U.S. coal production occurs in the GHG15 case, where an economy-wide CO_2 emissions price that rises to $53 per metric ton in 2040 leads to a 50-percent drop in coal production from the Reference case level in 2040. Across the remaining cases, variations range from 15 percent lower to 6 percent higher than production in the Reference case in 2020; and by 2040, as the gap in coal prices widens over time, the range of differences increases to 24 percent below and 16 percent above the Reference case in the High Coal Cost and Low Coal Cost cases, respectively. In two additional GHG cases developed for *AEO2013* (not shown in Figure 105), economy-wide CO_2 allowance fees are assumed to increase to $36 per metric ton in the GHG10 case and $89 per metric ton in the GHG25 case in 2040, resulting in total coal production in 2040 that is 25 percent lower and 72 percent lower, respectively, than in the Reference case.

Expected declines in mining productivity lead to further increases in average minemouth prices

Figure 106. Average annual minemouth coal prices by region, 1990-2040 (2011 dollars per million Btu)



In the *AEO2013* Reference case, the average real minemouth price for U.S. coal increases by 1.4 percent per year, from $2.04 per million Btu in 2011 to $3.08 in 2040, continuing the upward trend in coal prices that began in 2000 (Figure 106). A key factor underlying the higher coal prices in the projection is an expectation that coal mining productivity will continue to decline, but at slower rates than during the 2000s.

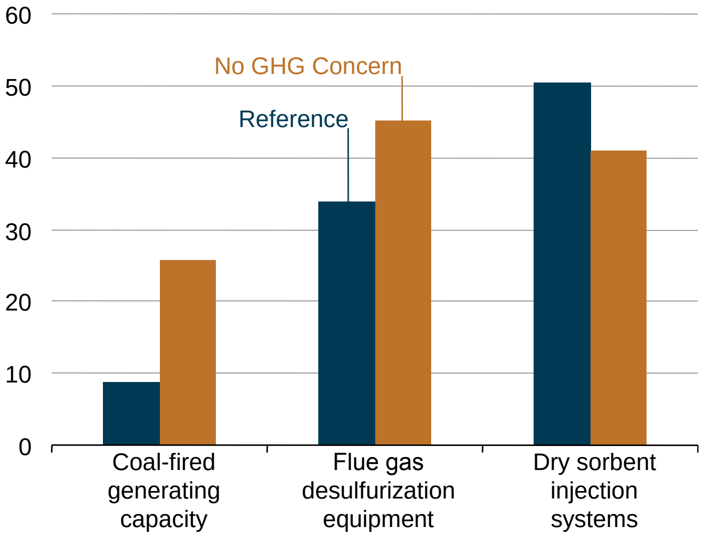
In the Appalachian region, the average minemouth coal price increases by 1.5 percent per year from 2011 to 2040. In addition to continued declines in coal mining productivity, the higher price outlook for the Appalachian region reflects a shift to higher-value coking coal, resulting from the combination of growing exports of coking coal and declining shipments of steam/thermal coal to domestic markets. Recent increases in the average price of Appalachian coal, from $1.31 per million Btu in 2000 to $3.33 per million Btu in 2011, in part as a result of significant declines in mining productivity over the past decade, have substantially reduced the competitiveness of Appalachian coal with coal from other regions.

In the Western and Interior coal supply regions, declines in mining productivity, combined with increasing production, lead to increases in the real minemouth price of coal, averaging 2.3 percent per year for the Western region and 1.2 percent per year for the Interior region from 2011 to 2040.

In two alternative coal cost cases developed for *AEO2013*, the average U.S. minemouth coal price in 2040 is as low as $1.70 per million Btu in the Low Coal Cost case (45 percent below the Reference case) and as high as $6.20 per million Btu in the High Coal Cost case (101 percent higher than in the Reference case). Results for the two cases, which are based on different assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates, are provided in Appendix D.

Concerns about future GHG policies affect builds of new coal-fired generating capacity

Figure 107. Cumulative coal-fired generating capacity additions and environmental retrofits in two cases, 2012-2040 (gigawatts)



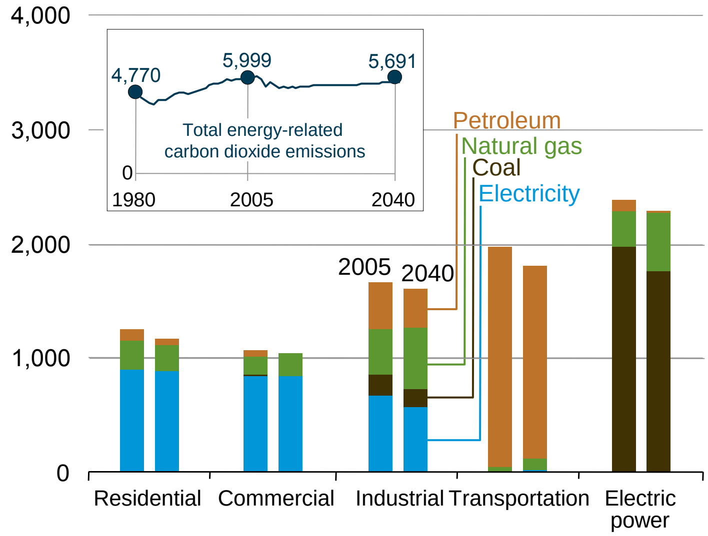
In the *AEO2013* Reference case, the cost of capital for investments in GHG-intensive technologies is increased by 3 percentage points, primarily to reflect the behavior of electricity generators who must evaluate long-term investments across a range of generating technologies in an environment where future restrictions of GHG emissions are likely. The higher cost of capital is used to estimate the costs for new coal-fired power plants without carbon capture and storage (CCS) and for capital investment projects at existing coal-fired power plants (excluding CCS). The No GHG Concern case illustrates the potential impact on energy investments when the cost of capital is not increased for GHG-intensive technologies.

In the No GHG Concern case, a lower cost of capital leads to the addition of 26 gigawatts of new coal-fired capacity from 2012 to 2040, up from 9 gigawatts in the Reference case (Figure 107). Nearly all projected builds in the Reference case are plants already under construction. As a result, additions of natural gas, nuclear, and renewable generating capacity all are slightly lower in the No GHG Concern case than in the Reference case.

In addition to affecting builds of new generating capacity, removing the premium for the cost of capital also influences capital investment projects at existing coal-fired power plants. In the No GHG Concern case, the lower cost of capital results in some additional retrofits of flue gas desulfurization (FGD) equipment relative to the Reference case, and fewer retrofits of dry sorbent injection (DSI) systems, which are a less capital-intensive option than FGD for controlling emissions of acid gases. To comply with the requirements specified in the Mercury and Air Toxics Standards (MATS), the *AEO2013* projections assume that coal-fired power plants must be equipped with either FGD equipment or DSI systems with full fabric filters.

Energy-related carbon dioxide emissions remain below their 2005 level through 2040

Figure 108. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2040 (million metric tons)



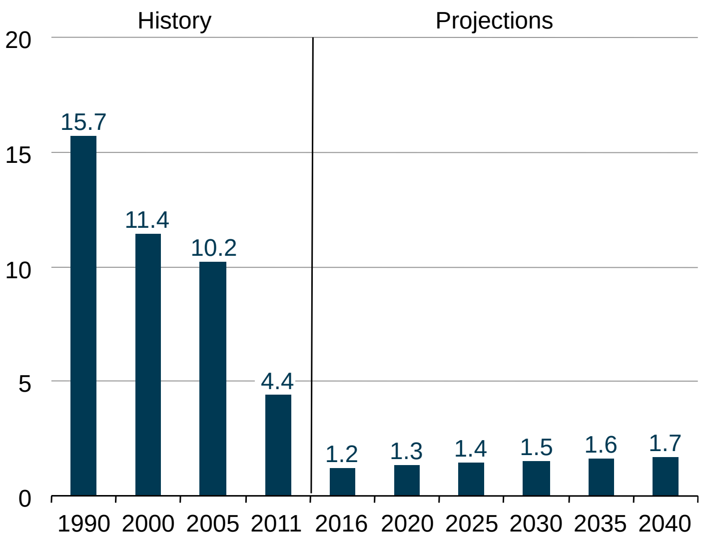
On average, energy-related CO_2 emissions in the *AEO2013* Reference case decline by 0.2 percent per year from 2005 to 2040, as compared with an average increase of 0.9 percent per year from 1980 to 2005. Reasons for the decline include: an expected slow and extended recovery from the recession of 2007-2009; growing use of renewable technologies and fuels; automobile efficiency improvements; slower growth in electricity demand; and more use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, energy-related CO_2 emissions in 2020 are 9.1 percent below their 2005 level. Energy-related CO_2 emissions total 5,691 million metric tons in 2040, or 308 million metric tons (5.1 percent) below their 2005 level (Figure 108).

Petroleum remains the largest source of U.S. energy-related CO_2 emissions in the projection, but its share falls to 38 percent in 2040 from 44 percent in 2005. CO_2 emissions from petroleum use, mainly in the transportation sector, are 448 million metric tons below their 2005 level in 2040.

Emissions from coal, the second-largest source of energy-related CO_2 emissions, are 246 million metric tons below the 2005 level in 2040 in the Reference case, and their share of total energy-related CO_2 emissions declines from 36 percent in 2005 to 34 percent in 2040. The natural gas share of total CO_2 emissions increases from 20 percent in 2005 to 28 percent in 2040, as the use of natural gas to fuel electricity generation and industrial applications increases. Emissions levels are sensitive to assumptions about economic growth, fuel prices, technology costs, and policies that are explored in many of the alternative cases completed for *AEO2013*.

Power plant emissions of sulfur dioxide are reduced by further environmental controls

Figure 109. Sulfur dioxide emissions from electricity generation, 1990-2040 (million short tons)



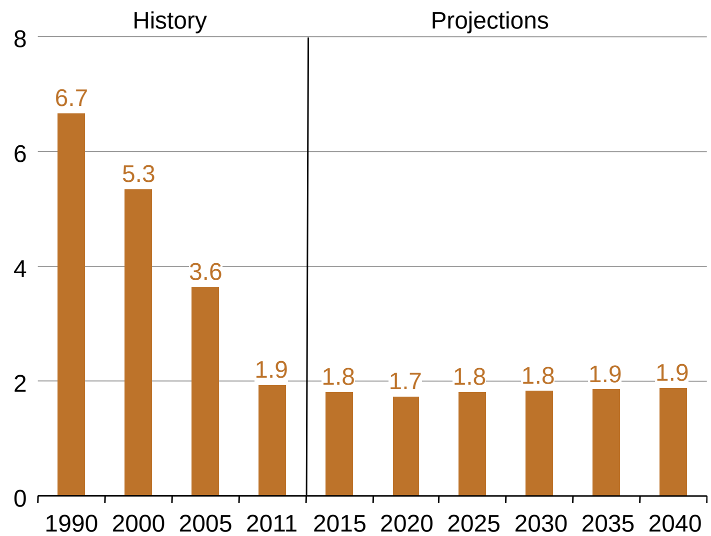
In the *AEO2013* Reference case, sulfur dioxide (SO_2) emissions from the U.S. electric power sector fall from 4.4 million short tons in 2011 to a range between 1.2 and 1.7 million short tons in the 2016-2040 projection period. The reduction occurs in response to the MATS [*142*]. Although SO_2 is not directly regulated by the MATS, the reductions are achieved as a result of acid gas limits that lead to the installation of FGD units or DSI systems, which also remove SO_2. *AEO2013* assumes that, in order to comply with MATS, coal-fired power plants must have one of the two technologies installed by 2016. Both technologies, which are used to reduce acid gas emissions regulated under MATS, also reduce SO_2 emissions.

EIA assumes a 95-percent SO_2 removal efficiency for FGD units and a 70-percent SO_2 removal efficiency for DSI systems paired with baghouse fabric filters. *AEO2013* also assumes that a baghouse fabric filter is required for all coal-fired plants in order to comply with the nonmercury metal emissions limits set forth by MATS [*143*, *144*].

From 2011 to 2040, approximately 34 gigawatts of coal-fired capacity is retrofitted with FGD units in the Reference case, and another 50 gigawatts is retrofitted with DSI systems. In 2016, all operating coal-fired generation units larger than 25 megawatts are assumed to have either DSI or FGD systems installed. After a 73-percent decrease from 2011 to 2016, SO_2 emissions increase slowly from 2016 to 2040 (Figure 109) as total electricity generation from coal-fired power plants increases. The increase is relatively small, however, because overall growth in generation from coal is slow, and the required installations of FGD and DSI equipment limit SO_2 emissions from plants in operation.

Nitrogen oxides emissions show little change from 2011 to 2040 in the Reference case

Figure 110. Nitrogen oxides emissions from electricity generation, 1990-2040 (million short tons)



Annual emissions of nitrogen oxides (NO_X) from the electric power sector, which totaled 1.9 million short tons in 2011, range between 1.6 and 2.1 million short tons from 2011 to 2040 (Figure 110). Annual NO_X emissions from electricity generation dropped by 47 percent from 2005 to 2011 as a result of the implementation of the Clean Air Interstate Rule (CAIR), which led to year-round operation of advanced pollution control equipment (that under the NO_X budget program operated during the summer season only) and to additional installations of NO_X pollution control equipment.

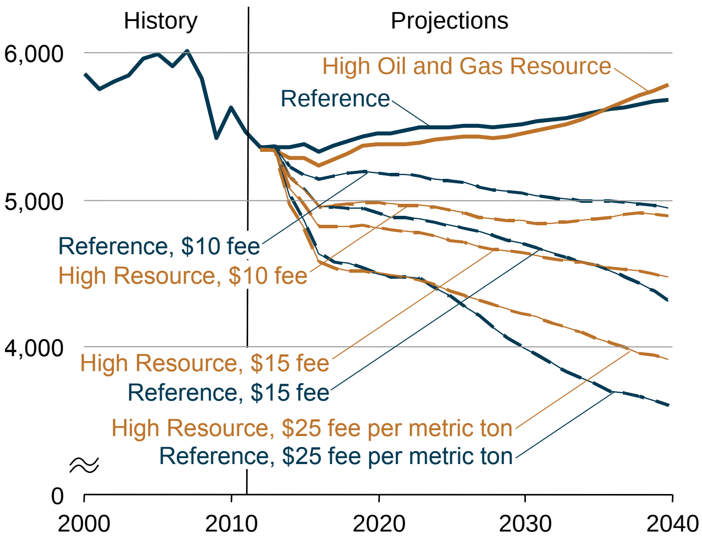
In the *AEO2013* Reference case, annual NO_X emissions in 2040 are 4 percent below the 2011 level, despite a 6-percent increase in annual electricity generation from coal-fired power plants over the period. The drop in emissions is primarily a result of CAIR, which established an annual cap-and-trade program for NO_X emissions in 25 states and the District of Columbia. A slight rise in NO_X emissions after 2020 corresponds to a projected recovery in coal-fired generation.

MATS does not have a direct effect on NO_X emissions, because none of the potential technologies required to comply with MATS has a significant impact on NO_X emissions. However, because MATS contributes to a reduction in coal-fired generation nationwide, it indirectly reduces NO_X emissions from the power sector in states not affected by CAIR.

From 2011 to 2040, 15.4 gigawatts of coal-fired capacity is retrofitted with NO_X controls in the *AEO2013* Reference case. Coal-fired power plants can be retrofitted with three types of NO_X control technologies: selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), or low-NO_X burners, depending on the specific characteristics of the plant, including boiler configuration and the type of coal used. SCRs make up 90 percent of the NO_X controls installed in the Reference case, SNCRs 5 percent, and low-NO_X burners 5 percent.

Energy-related carbon dioxide emissions are sensitive to potential policy changes

Figure 111. Energy-related carbon dioxide emissions in two cases with three levels of emissions fees, 2000-2040 (million metric tons)



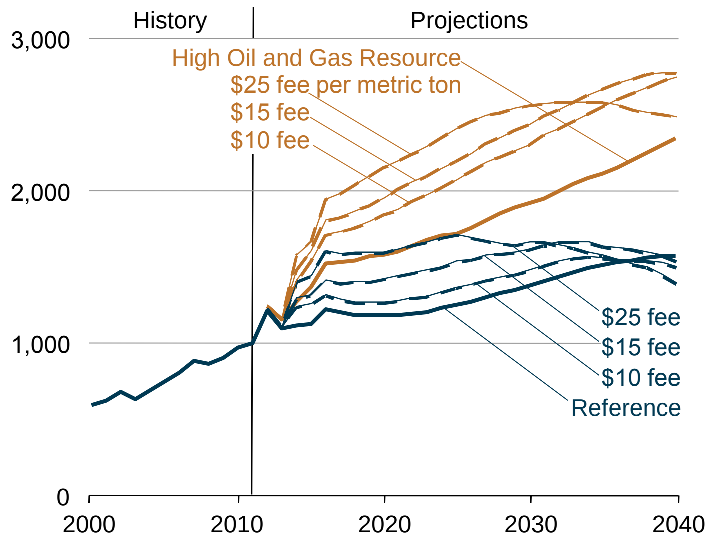
Although the *AEO2013* Reference case assumes that current laws and regulations remain in effect through 2040, the potential impacts of a future fee on CO_2 emissions are examined in three carbon-fee cases, starting at $10, $15, and $25 per metric ton CO_2 in 2014 and rising by 5 percent per year annually thereafter. The three fee cases were combined with the Reference case and also, because of uncertainty about the growing role of natural gas in the U.S. energy landscape and how it might affect efforts to reduce GHG emissions, with the High Oil and Gas Resource case (Figure 111).

Emissions fees would have a significant impact on U.S. energy-related CO_2 emissions. They would encourage all energy producers and consumers to shift to lower-carbon or zero-carbon energy sources. Relative to 2005 emissions levels, energy-related CO_2 emissions are 14 percent, 19 percent, and 28 percent lower in 2025 in the $10, $15, and $25 fee cases using Reference case resources, respectively, and 17 percent, 28 percent, and 40 percent lower in 2040. When combined with High Oil and Gas Resource assumptions, the CO_2 fees tend to lead to slightly greater emissions reductions in the near term and smaller reductions in the long term.

The alternative assumptions about natural gas resources have only small impacts on energy-related CO_2 emissions in all the cases except the $25 fee cases. Although more abundant and less expensive natural gas in the High Oil and Gas Resource cases does lead to less coal use and more natural gas use, it also reduces the use of renewable and nuclear fuels and increases energy consumption overall. In the long run, the emissions reductions achieved by shifting from coal to natural gas are offset by the impacts of reduced use of renewables and nuclear power for electricity generation, and by higher overall levels of energy consumption.

Carbon dioxide fee cases generally increase the use of natural gas for electricity generation

Figure 112. Natural gas-fired electricity generation in six CO_2 fee cases, 2000-2040 (billion kilowatthours)



The role of natural gas in the CO_2 fee cases varies widely over time and, in addition, over the range of assumptions about natural gas resources. When CO_2 fees are assumed to be introduced in 2014, natural gas-fired generation increases sharply. The role of natural gas in the CO_2 fee cases begins declining between 2025 and 2030, however, as power companies bring more new nuclear and renewable plants on line (Figure 112).

After accounting for about 50 percent of all U.S. electricity generation for many years, coal's share has declined over the past few years because of growing competition from efficient natural gas-fired plants with access to low-cost natural gas. In the Reference case, the share of generation accounted for by coal falls from 42 percent in 2011 to 38 percent in 2025 and 35 percent in 2040. Coal's share falls even further in the CO_2 fee cases, to a range between 6 percent and 31 percent in 2025 and between 1 percent and 24 percent in 2040.

As the fee for CO_2 emissions increases over time, power companies reduce their use of coal and increase their use of nuclear power, renewables, and natural gas. The nuclear and renewable shares of total generation increase in most of the CO_2 fee cases, particularly in the later years of the projections. In the Reference case, nuclear generation accounts for 20 percent of the total in 2025 and 17 percent in 2040. In the CO_2 fee cases, the nuclear share varies from 20 to 24 percent in 2025 and 18 to 37 percent in 2040. The renewable share of total generation in 2025 is 14 percent in the Reference case, increasing to 16 percent in 2040. In the CO_2 fee cases the renewable share is generally higher, between 15 percent and 21 percent in 2025 and between 17 percent and 31 percent in 2040.

Endnotes for Market trends

Links current as of March 2013

124. The industrial sector includes manufacturing, agriculture, construction, and mining. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.

125. These expenditures relative to GDP are not the energy-share of GDP, since expenditures include energy as an intermediate product. The energy-share of GDP corresponds to the share of value added due to domestic energy-producing sectors, which would exclude the value of energy as an intermediate product.

126. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 31*, ORNL-6987 (Oak Ridge, TN: July 2012), Chapter 2, Table 2.1, "U.S. Consumption of Total Energy by End-Use Sector, 1973-2011."

127. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 31*, ORNL-6987 (Oak Ridge, TN: July 2012), Chapter 4, Table 4.6, "New Retail Sales of Trucks 10,000 Pounds GVWR and Less in the United States, 1970-2011."

128. U.S. Department of Transportation, National Highway Safety Administration, "Summary of Fuel Economy Performance" (Washington, DC: October 2012), http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/Oct2012_Summary_Report.pdf.

129. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 75, No. 88 (Washington, DC: May 7, 2010), https://www.federalregister.gov/articles/2010/05/07/2010-8159/light-duty-vehicle-greenhouse-gas-emission-standards-and-corporate-average-fuel-economy-standards.

130. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.

131. Light-duty vehicle fuel economy includes alternative-fuel vehicles and banked credits towards compliance.

132. The factors that influence decisionmaking on capacity additions include electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different generation options, fuel prices, state RPS programs, and the availability of federal tax credits for some technologies.

133. Unless otherwise noted, the term capacity in the discussion of electricity generation indicates utility, nonutility, and CHP capacity.

134. Costs are for the electric power sector only.

135. The levelized costs reflect the average of regional costs. For detailed discussion of levelized costs, see U.S. Energy Information Administration, "Levelized Cost of New Generation Resources in the *Annual Energy Outlook 2013*," http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

136. Next-generation biofuels include pyrolysis oils, biomass-derived Fisher-Tropsch liquids, and renewable feedstocks used for on-site production of diesel and gasoline.

137. xTL refers to liquid fuels that are created from biomass, as in biomass-to-liquids (BTL); from natural gas, as in GTL; and from coal, as in CTL.

138. Permeability is a laboratory measurement of a rock's ability to transmit liquid and gaseous fluids through its pore spaces. High-permeability sandstones have many large and well-connected pore spaces that readily transmit fluids, while low-permeability shales have smaller and fewer interconnected pore spaces that retard fluid flow. Laboratory measurements of rock permeability are stated in terms of darcies or millidarcies.

139. One option for balancing the mix of crudes might be to allow the export of domestically produced light crude in exchange for heavier crudes. Crude exports and swaps, however, are currently permitted only in limited cases and require a license from the Department of Commerce.

140. U.S. Environmental Protection Agency, "EPA Finalizes 2012 Renewable Fuel Standards," EPA-420-F-11-044 (Washington, DC: December 2011), http://www.epa.gov/otaq/fuels/renewablefuels/documents/420f11044.pdf.

141. R. Schnepf and B.D. Yacobucci, *Renewable Fuel Standard (RFS): Overview and Issues* (Washington, DC: Congressional Research Service, January 23, 2012), http://www.fas.org/sgp/crs/misc/R40155.pdf.

142. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," http://www.epa.gov/mats.

143. Recent analysis performed by the EPA indicates that upgraded electrostatic precipitators may also enable coal-fired power plants to meet the nonmercury metal emissions control requirement for MATS. This assumption was not included in *AEO2013* but will be revisited in future *AEO*s.

144. U.S. Energy Information Administration, "Dry sorbent injection may serve as a key pollution control technology at power plants," *Today in Energy* (March 16, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=5430.

Comparison with other projections

Energy Information Administration (EIA) and other contributors have endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives. None of the EIA or any of the other contributors shall be responsible for any loss sustained due to reliance on the information included in this report.

Only IHS Global Insight (IHSGI) produces a comprehensive energy projection with a time horizon similar to that of the *Annual Energy Outlook 2013 (AEO2013)*. Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from IHSGI, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2013* Reference case.

1. Economic growth

The range of projected economic growth in the outlooks included in the comparison tends to be wider over the first 5 years of the projection than over a longer period, because the group of variables—such as population, productivity, and labor force growth—that influence long-run economic growth is smaller than the group of variables that affect projections of short-run growth. The average annual rate of growth of real gross domestic product (GDP) from 2011 to 2015 (in 2005 dollars) ranges from 2.2 percent to 2.9 percent (Table 8). From 2011 to 2025, the 14-year average annual growth rate ranges from 2.5 percent to 2.8 percent.

From 2011 to 2015, real GDP grows at a 2.5-percent average annual rate in the *AEO2013* Reference case, lower than projected by the Congressional Budget Office (CBO), the Social Security Administration (SSA) (in *The 2011 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds*), Oxford Economic Group (OEG), and the Interindustry Forecasting Project at the University of Maryland (INFORUM) but higher than projected by Blue Chip Consensus (Blue Chip) and the Office of Management and Budget (OMB). The *AEO2013* projection of GDP growth is similar to the average annual rate of 2.5 percent over the same period projected by IHSGI and by the International Energy Agency (IEA), in its November 2012 *World Energy Outlook* Current Policies Scenario.

The average annual GDP growth of 2.6 percent in the *AEO2013* Reference case from 2011 to 2025 is at the mid-range of the outlooks, with OMB, CBO, and the SSA projecting the strongest recovery from the 2007-2009 recession. OMB and CBO project average annual GDP growth from 2011 to 2023 of 2.8 percent and 2.7 percent, respectively. The SSA and OEG project annual average growth of 2.7 percent from 2011 to 2025. IEA projects growth at a rate similar to that in the *AEO2013* Reference case from 2011 to 2025—as do IHSGI and INFORUM—at 2.6 per year over the next 14 years. Blue Chip and ExxonMobil project growth at 2.5 percent, or 0.1 percentage point lower than in the *AEO2013* Reference case.

There are few public or private projections of GDP growth for the United States that extend to 2040. The *AEO2013* Reference case projects 2.5-percent average annual GDP growth from 2011 to 2040, consistent with trends in labor force and productivity growth. IHSGI and INFORUM also project GDP growth averaging 2.5 percent per year from 2011 to 2040. The SSA, ExxonMobil, and IEA project a lower rate of 2.4 percent per year, while the OEG and ICF International (ICF) project a higher rate of 2.6 percent per year from 2011 to 2040.

Table 8. Comparisons of average annual economic growth projections, 2011-2040

	Average annual percentage growth rates			
Projection	2011-2015	2011-2025	2025-2040	2011-2040
AEO2013 (Reference case)	2.5	2.6	2.4	2.5
AEO2012 (Reference case)[a]	2.7	2.6	2.5	2.6
IHS Global Insight (August 2012)	2.5	2.6	2.5	2.5
OMB (January 2013)[a]	2.2	2.8	--	--
CBO (February 2013)[a]	2.6	2.7	--	--
INFORUM (November 2012)	2.6	2.6	2.4	2.5
Social Security Administration (August 2012)	2.9	2.7	2.2	2.4
IEA (2012)[b]	2.5	2.6	--	2.4
Blue Chip Consensus (October 2012)[a]	2.4	2.5	--	--
ExxonMobil	--	2.5	2.2	2.4
ICF International	--	--	--	2.6
Oxford Economics Group (January 2013)	2.7	2.7	2.6	2.6

-- = not reported or not applicable.

[a]OMB, CBO, and Blue Chip forecasts end in 2022, and growth rates cited are for 2011-2022. *AEO2012* projections end in 2035, and growth rates cited are for 2011-2035.

[b]IEA publishes U.S. growth rates for certain intervals: 2010-2015 growth is 2.5 percent, 2010-2020 growth is 2.6 percent, and 2010-2035 growth is 2.4 percent.

2. Oil prices

In *AEO2013*, oil prices are represented by spot prices for Brent crude. Prices rise in the Reference case from $111 per barrel in 2011 to about $117 per barrel in 2025 and $163 per barrel in 2040 (Table 9). The price rise starts slowly, then accelerates toward the end of the projection period. In the *Annual Energy Outlook 2012 (AEO2012)* Reference case, where oil prices were represented by the West Texas Intermediate (WTI) spot price, prices rose more sharply in the early years and more slowly at the end of the projection period. *AEO2013* also presents the annual average WTI spot price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and includes the U.S. annual average refiners' acquisition cost (RAC) of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners. In 2011, the WTI and Brent prices differed by $16 per barrel. In the *AEO2013* Reference case, the gap closes to a difference of $2 per barrel in 2025, following resolution of transportation system constraints in the United States. In each of the other outlooks in the comparison, oil spot prices are based on either Brent or WTI prices, with the exception of IEA, which represents the international average of crude oil import prices.

Market volatility and different assumptions about the future of the world economy are reflected in the range of oil price projections for both the near and long term; however, most projections show oil prices rising over the entire projection period. The projections for 2025 range from $78 per barrel (WTI) to $137 per barrel (Brent) in 2025—a span of $59 per barrel—and from $81 per barrel (WTI) to $163 per barrel (Brent) in 2040—a span of $82 per barrel. The wide range underscores the uncertainty inherent in the projections. The range of the projections is encompassed in the range of the *AEO2013* Low and High Oil Price cases, from $68 per barrel (WTI) to $173 per barrel (Brent) in 2025 and from $71 per barrel (WTI) to $213 per barrel (Brent) in 2035.

3. Total energy consumption

Four projections by other organizations—INFORUM, IHSGI, ExxonMobil, and IEA—include energy consumption by sector (Table 10). To allow comparison with the IHSGI projection, the *AEO2013* Reference case was adjusted to remove coal-to-liquids (CTL) heat and power, natural gas-to-liquids heat and power, biofuels heat and co-products, and natural gas feedstock use. To allow comparison with the ExxonMobil projection, electricity consumption in each sector was removed from the *AEO2013* Reference case. To allow comparison with the IEA projections, the *AEO2013* Reference case projections for the residential and commercial sectors were combined to produce a buildings sector projection. The IEA projections have a base year of 2010, as opposed to 2011 in the other projections. The INFORUM and IEA projections extend only through 2035.

ExxonMobil includes a cost for carbon dioxide (CO_2) emissions in their projection, which helps to explain the lower level of consumption in their outlook. Although the IEA's central case also includes a cost for CO_2 emissions, its Current Policies Scenario (which assumes that no new policies are added to those in place in mid-2012) is used for comparison in this analysis, because it corresponds better with the assumptions in the *AEO2013* Reference case. ExxonMobil and IEA show lower total energy consumption across all years in comparison with the *AEO2013* Reference case. Total energy consumption is higher in all years of the IHSGI projection than in the *AEO2013* Reference case but starts from a lower level in 2011.

The INFORUM projection of total energy consumption in 2035 is 2.4 quadrillion British thermal units (Btu) higher than the *AEO2013* Reference case projection, with the transportation sector 2.4 quadrillion Btu higher, the buildings sector 1 quadrillion Btu higher, and the industrial sector 1 quadrillion Btu lower. For the transportation sector, the difference could be related to vehicle efficiency, as the INFORUM projection for motor gasoline consumption (2 quadrillion Btu lower than *AEO2013*) is comparable with the EIA projection in *AEO2012*, which did not include the efficiency standard for vehicle model years 2017 through 2025. Energy consumption growth in the INFORUM projection is weaker than projected in *AEO2013* through 2020 but stronger after 2020.

IHSGI projects significantly higher electricity consumption for all sectors than in the *AEO2013* Reference case, which helps to explain much of the difference in total energy consumption between the two projections. In the IHSGI projection, the electric power sector consumes 10.0 quadrillion Btu more energy in 2040 than in the *AEO2013* Reference case. The greater use of electricity in the IHSGI projection, including 150 trillion Btu used in the transportation sector (more than double the amount in *AEO2013*), also results in higher electricity prices than in the *AEO2013* Reference case.

Table 9. Comparisons of oil price projections, 2025, 2035, and 2040 (2011 dollars per barrel)

			Projections					
	2011		2025		2035		2040	
	WTI	Brent	WTI	Brent	WTI	Brent	WTI	Brent
AEO2013 (Reference case)	94.86	111.26	115.36	117.36	143.41	145.41	160.68	162.68
AEO2012 (Reference case)	94.82	--	135.35	--	148.03	--	--	--
Energy Ventures Analysis, Inc. (EVA)	--	--	78.18	--	82.16	--	87.43	--
IEA (Current Policies Scenario)	--	107.60	--	135.70	--	145.00	--	--
INFORUM	--	111.26	--	136.77	--	149.55	--	--
IHSGI	94.88	--	93.05	--	86.25	--	81.20	--

Total energy consumption declines in the ExxonMobil projection, primarily as a result of the inclusion of a tax on CO_2 emissions, which is not considered in the *AEO2013* Reference case. Energy consumption in the transportation and industrial sectors declines from 2011 levels in the ExxonMobil projection, based on expected policy changes and technology improvements.

Total energy consumption in the IEA projection is higher in 2035 than in 2010 because of increased consumption in the buildings sector, where an increase of 3.7 quadrillion Btu includes 3.1 quadrillion Btu of additional electricity demand. Energy consumption in the transportation and industrial sectors declines from 2020 to 2030 in the IEA projection, by less than 1 quadrillion Btu in each sector. IEA projects little change in energy use for those two sectors from 2030 to 2035, with industrial energy consumption

Table 10. Comparisons of energy consumption by sector projections, 2025, 2035, and 2040 (quadrillion Btu)

Sector	*AEO2013* Reference	INFORUM	IHSGI	ExxonMobil	IEA
			2011		
Residential	11.3	11.5	10.8	--	--
Residential excluding electricity	6.4	6.6	6.0	5.0	--
Commercial	8.6	8.6	8.5	--	--
Commercial excluding electricity	4.1	4.1	4.0	4.0	--
Buildings sector	19.9	20.1	19.3	--	19.3[a]
Industrial	24.0	23.6	--	--	23.7[a]
Industrial excluding electricity	20.7	20.2	--	20.0	--
Losses[b]	0.7	--	--	--	--
Natural gas feedstocks	0.5	--	--	--	--
Industrial removing losses and feedstocks	22.9	--	21.7	--	--
Transportation	27.1	27.2	26.2	27.0	23.1[a]
Electric power	39.4	39.2	40.5	37.0	37.2[a]
Less: electricity demand[c]	12.7	12.8	12.7	--	15.0[a]
Electric power losses	26.7	--	--	--	--
Total primary energy	**97.7**	**97.3**	**--**	**93.0**	**87.9[a]**
Excluding losses[b] and feedstocks	**96.6**	**--**	**95.0**	**--**	**--**
			2025		
Residential	11.0	11.5	11.8	--	--
Residential excluding electricity	6.0	6.3	5.8	6.0	--
Commercial	9.2	9.5	9.8	--	--
Commercial excluding electricity	4.3	4.3	4.0	3.0	--
Buildings sector	20.3	21.0	21.6	--	--
Industrial	27.5	25.4	--	--	--
Industrial excluding electricity	23.4	21.8	--	20.0	--
Losses[b]	1.1	--	--	--	--
Natural gas feedstocks	0.6	--	--	--	--
Industrial removing losses and feedstocks	25.9	--	23.6	--	--
Transportation	26.7	27.5	25.1	26.0	--
Electric power	42.1	42.6	49.0	39.0	--
Less: electricity demand[c]	14.1	14.0	16.1	--	--
Electric power losses	27.9	--	--	--	--
Total primary energy	**102.3**	**102.5**	**--**	**94.0**	**--**
Excluding losses[b] and feedstocks	**100.7**	**--**	**103.2**	**--**	**--**

-- = not reported.
See notes at end of table.

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declining very slowly and transportation energy consumption increasing slightly. IEA projects total energy consumption that is higher than ExxonMobil's projection in 2035, but considerably lower than in the *AEO2013* Reference case for both 2030 and 2035.

4. Electricity

Table 11 compares summary results from the *AEO2013* Reference case with projections from EVA, IHSGI, INFORUM, ICF, and the National Renewable Energy Laboratory (NREL). In 2025, total electricity sales range from a low of 4,095 billion kilowatthours (INFORUM) to a high of 4,712 billion kilowatthours (IHSGI) [*145*]. The *AEO2013* Reference case projects 4,140 billion kilowatthours

Table 10. Comparisons of energy consumption by sector projections, 2025, 2035, and 2040 (quadrillion Btu) (continued)

Sector	*AEO2013* Reference	INFORUM	IHSGI	ExxonMobil	IEA
			2035		
Residential	11.4	11.9	12.5	--	--
Residential excluding electricity	5.7	6.1	5.7	5.0	--
Commercial	9.9	10.3	10.8	--	--
Commercial excluding electricity	4.4	4.5	4.1	3.0	--
Buildings sector	21.2	22.2	23.3	--	23.0
Industrial	27.8	26.8	--	--	24.2
Industrial excluding electricity	23.9	23.4	--	19.0	--
Losses[b]	1.4	--	--	--	--
Natural gas feedstocks	0.5	--	--	--	--
Industrial removing losses and feedstocks	25.9	--	23.4	--	--
Transportation	26.4	28.8	22.9	25.0	22.7
Electric power	44.1	44.1	53.6	39.0	42.7
Less: electricity demand[c]	15.1	15.1	18.1	--	18.6
Electric power losses	29.0	--	--	--	--
Total primary energy	**104.4**	**106.8**	**--**	**91.0**	**93.6**
Excluding losses[b] and feedstocks	**102.6**	**--**	**105.1**	**--**	**--**
			2040		
Residential	11.6	--	12.9	--	--
Residential excluding electricity	5.5	--	5.7	5.0	--
Commercial	10.2	--	11.1	--	--
Commercial excluding electricity	4.5	--	4.1	3.0	--
Buildings sector	21.8	--	24.0	--	--
Industrial	28.7	--	--	--	--
Industrial excluding electricity	24.8	--	--	18.0	--
Losses[b]	1.9	--	--	--	--
Natural gas feedstocks	0.4	--	--	--	--
Industrial removing losses and feedstocks	26.4	--	23.5	--	--
Transportation	27.1	--	22.0	25.0	--
Electric power	45.7	--	55.9	39.0	--
Less: electricity demand[c]	15.7	--	19.1	--	--
Electric power losses	30.0	--	--	--	--
Total primary energy	**107.6**	**--**	**--**	**89.0**	**--**
Excluding losses[b] and feedstocks	**105.3**	**--**	**106.3**	**--**	**--**

-- = not reported.
[a]IEA data are for 2010.
[b]Losses in CTL and biofuel production.
[c]Energy consumption in the sectors includes electricity demand purchases from the electric power sector, which are subtracted to avoid double counting in deriving total primary energy consumption.

of total electricity sales in 2025, EVA projects 4,311 billion kilowatthours in 2025, and NREL projects 4,487 billion kilowatthours in 2026. In comparison with the other projections, IHSGI shows higher sales across all sectors in 2025, with the exception of the commercial sector (1,709 billion kilowatthours), where the EVA projection of 1,824 billion kilowatthours is 115 billion kilowatthours higher. The higher total in the commercial sector counterbalances EVA's lower projection of 736 billion kilowatthours for the industrial sector, compared with 1,186 billion kilowatthours in the *AEO2013* Reference case, 1,246 billion kilowatthours in the IHSGI projection, and 1,033 billion kilowatthours in the INFORUM projection.

Total electricity sales in 2035 in the IHSGI projection (5,316 billion kilowatthours) are higher than in the others: 4,406 billion kilowatthours in the INFORUM projection, 4,421 billion kilowatthours in the *AEO2013* Reference case, 4,824 billion kilowatthours (in 2036) in the NREL projection, and 4,923 billion kilowatthours in the EVA projection. EVA projects the highest level of electricity sales in both the residential and commercial sectors in 2035 but a lower level of industrial sales in comparison with the other projections. Electricity sales in the industrial sector in the IHSGI projection are 1,332 billion kilowatthours in 2035, as compared with 1,142 billion kilowatthours in the *AEO2013* Reference case, 978 billion kilowatthours in the INFORUM projection, and only 515 billion kilowatthours in the EVA projection. Total electricity sales in 2040 are again led by the IHSGI projection, with 5,602 billion kilowatthours, followed by 5,238 billion kilowatthours in the EVA projection, 4,608 billion kilowatthours in the *AEO2013* Reference case, and 4,940 billion kilowatthours in the NREL projection.

Table 11. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted)

Projection	2011	*AEO2013* Reference case	Other projections				
			EVA	IHSGI	INFORUM	ICF	NREL
		2025					2026
Average end-use price (2011 cents per kilowatthour)[a]	9.9	9.5	--	11.2	10.0	--	10.4
Residential	11.7	11.6	--	13.3	11.8	--	--
Commercial	10.2	9.7	--	11.6	10.3	--	--
Industrial	6.8	6.5	--	7.6	6.8	--	--
Total generation including CHP plus imports	**4,130**	**4,612**	**4,570**	**5,207**	**4,296**	**4,860**	**4,693**
Coal	1,730	1,727	1,726	1,605	--	--	1,860
Petroleum	28	18	--	33	--	--	0
Natural gas[b]	1,000	1,252	1,387	1,732	--	--	1,041
Nuclear	790	912	890	923	--	--	794
Hydroelectric/other[c]	544	681	567	852	--	--	997
Net imports	37	22	--	62	--	--	--
Electricity sales[d]	3,725	4,140	4,311	4,712	4,095	--	4,487
Residential	1,424	1,488	1,750	1,756	1,536	--	--
Commercial/other[e]	1,326	1,466	1,824	1,709	1,526	--	--
Industrial	976	1,186	736	1,246	1,033	--	--
Capacity, including CHP (gigawatts)[f]	1,049	1,098	1,141	1,237	--	1,135	1,146
Coal	318	276	255	278	--	249	273
Oil and natural gas	463	500	568	555	--	546	515
Nuclear	101	114	108	115	--	106	102
Hydroelectric/other[g]	167	208	210	289	--	234	257
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	82	151	83	--	106	102
Coal	--	49	73	46	--	73	33
Oil and natural gas	--	32	73	36	--	29	69
Nuclear	--	1	3	1	--	3	0
Hydroelectric/other[g]	--	1	2	--	--	0	0

-- = not reported.
See notes at end of table.

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IHSGI, INFORUM, and the *AEO2013* Reference case provide projections for average electricity prices by sector for 2025 and 2035. NREL provides a U.S. average electricity price projection for 2026 and 2036, but not by sector. IHSGI, NREL, and the *AEO2013* Reference case provide projections for average electricity prices in 2040. Average electricity prices in the *AEO2013* Reference case are 9.5 cents per kilowatthour in 2025, 10.1 cents per kilowatthour in 2035, and 10.8 cents per kilowatthour in 2040. Average electricity prices in the INFORUM projection are 10.0 cents per kilowatthour in 2025 and 10.5 cents per kilowatthour in 2035 [*146*]. IHSGI projects considerably higher average electricity prices than either the *AEO2013* Reference case or INFORUM, at 11.2 cents per kilowatthour in 2025, 11.9 cents per kilowatthour in 2035, and 12.2 cents per kilowatthour in 2040. NREL projects overall average electricity prices of 10.4 cents per kilowatthour in 2026, 11.7 cents per kilowatthour in 2036, and 12.0 cents per kilowatthour in 2040 (the NREL prices were provided in 2009 dollars).

In all the projections, average electricity prices by sector follow patterns similar to changes in the weighted average electricity price across all sectors (including transportation services). The lowest prices by sector in 2025 are in the *AEO2013* Reference case (11.6 cents per kilowatthour for the residential sector, 9.7 cents per kilowatthour for the commercial sector, and 6.5 cents per kilowatthour for the industrial sector). The highest average electricity prices by sector in 2025 are in the IHSGI projection (13.3 cents per kilowatthour for the residential sector, 11.6 cents per kilowatthour for the commercial sector, and 7.6 cents per

Table 11. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) (continued)

Projection	2011	*AEO2013* Reference case	Other projections EVA	IHSGI	INFORUM	ICF	NREL
		2035					2036
Average end-use price (2011 cents per kilowatthour)[a]	9.9	10.1	--	11.9	10.5	--	11.7
Residential	11.7	12.1	--	14.1	12.2	--	--
Commercial	10.2	10.1	--	12.3	10.6	--	--
Industrial	6.8	7.1	--	8.1	7.1	--	--
Total generation including CHP plus imports	**4,130**	**4,989**	**5,005**	**5,870**	**4,601**	**5,339**	**4,847**
Coal	1,730	1,807	1,754	1,463	--	--	1,703
Petroleum	28	18	--	35	--	--	0
Natural gas[b]	1,000	1,519	1,701	2,271	--	--	1,730
Nuclear	790	875	839	953	--	--	510
Hydroelectric/other[c]	544	760	711	1,074	--	--	904
Net imports	37	10	--	73	--	--	--
Electricity sales[d]	3,725	4,421	4,923	5,316	4,406	--	4,824
Residential	1,424	1,661	2,116	2,001	1,718	--	--
Commercial/other[e]	1,326	1,618	2,292	1,983	1,710	--	--
Industrial	976	1,142	515	1,332	978	--	--
Capacity, including CHP (gigawatts)[f]	1,049	1,206	1,263	1,420	--	1,285	1,253
Coal	318	277	255	260	--	245	238
Oil and natural gas	463	587	655	676	--	665	654
Nuclear	101	109	103	120	--	80	67
Hydroelectric/other[g]	167	233	250	364	--	295	294
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	100	161	115	--	133	243
Coal	--	49	77	68	--	82	70
Oil and natural gas	--	44	74	38	--	29	138
Nuclear	--	6	9	9	--	21	35
Hydroelectric/other[g]	--	1	2	--	--	0	0

-- = not reported.
See notes at end of table.

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kilowatthour for the industrial sector). The *AEO2013* Reference case, IHSGI, and NREL reflect similar price patterns for 2035 (or 2036 for NREL) and 2040.

Total U.S. electricity generation plus imports in 2025 range from a low of 4,296 billion kilowatthours in the INFORUM projection to a high of 5,207 billion kilowatthours in the IHSGI projection. Within that range, the *AEO2013* Reference case projects total generation of 4,612 billion kilowatthours. Coal continues to represent the largest share of generation in 2025 in the *AEO2013* Reference case, which reports 1,727 billion kilowatthours from coal versus 1,252 billion kilowatthours from natural gas. By comparison, the natural gas share of total generation in the IHSGI projection in 2025 surpasses generation from coal by 126 billion kilowatthours, with 1,732 billion kilowatthours of generation from natural gas and 1,605 billion kilowatthours from coal. IHSGI projects 1,646 billion kilowatthours of electricity generation from both coal and natural gas in 2023, with the natural

Table 11. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) (continued)

Projection	2011	*AEO2013* Reference case	Other projections: EVA	IHSGI	INFORUM	ICF	NREL
		2040					
Average end-use price (2011 cents per kilowatthour)[a]	9.9	10.8	--	12.2	--	--	12.0
Residential	11.7	12.7	--	14.4	--	--	--
Commercial	10.2	10.8	--	12.5	--	--	--
Industrial	6.8	7.8	--	8.3	--	--	--
Total generation including CHP plus imports	**4,130**	**5,230**	**5,479**	**6,189**	**--**	**--**	**4,913**
Coal	1,730	1,829	1,740	1,418	--	--	1,620
Petroleum	28	18	--	36	--	--	0
Natural gas[b]	1,000	1,582	2,330	2,506	--	--	1,870
Nuclear	790	903	756	991	--	--	442
Hydroelectric/other[c]	544	879	653	1,164	--	--	981
Net imports	37	18	--	73	--	--	--
Electricity sales[d]	3,725	4,608	5,238	5,602	--	--	4,940
Residential	1,424	1,767	2,303	2,116	--	--	--
Commercial/other[e]	1,326	1,697	2,528	2,109	--	--	--
Industrial	976	1,145	407	1,378	--	--	--
Capacity, including CHP (gigawatts)[f]	1,049	1,293	--	1,495	--	--	1,295
Coal	318	278	--	251	--	--	224
Oil and natural gas	463	632	--	722	--	--	691
Nuclear	101	113	--	125	--	--	58
Hydroelectric/other[g]	167	270	--	396	--	--	322
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	103	--	128	--	--	276
Coal	--	49	--	80	--	--	86
Oil and natural gas	--	46	--	38	--	--	146
Nuclear	--	7	--	9	--	--	44
Hydroelectric/other[g]	--	1	--	--	--	--	0

-- = not reported.

[a]Average end-use price includes the transportation sector, NREL end-use prices expressed in 2009 dollars.

[b]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas.

[c]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies.

[d]Electricity sales for EVA and INFORUM reflect the sum of the individual sector level sales.

[e]"Other" includes sales of electricity to government and other transportation services.

[f]*AEO2013* capacity is net summer capability, including CHP plants and end-use generators.

[g]"Other" includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, wind, pumped storage, and fuel cells.

[h]IHSGI cumulative capacity retirements are calculated from annual totals. *AEO2013* retirements are for electric power sector only.

gas total exceeding that for coal in 2024 and beyond as a result of the assumed implementation of a carbon tax in the IHSGI projection. Conversely, coal continues to represent the largest share of generation in the *AEO2013* Reference case in 2035—1,807 billion kilowatthours as compared with 1,519 billion kilowatthours from natural gas. The *AEO2013* Reference case is based on current regulations and policies and does not assume a carbon tax. In 2035, the natural gas share of total generation in the IHSGI projection exceeds generation from coal by 808 billion kilowatthours. In the *AEO2013* Reference case, coal continues to represent the largest share of generation in 2040 at 1,829 billion kilowatthours, compared with 1,582 billion kilowatthours from natural gas. In comparison, the natural gas share of total generation in 2040 in the IHSGI projection widens its lead over coal by 1,088 billion kilowatthours. In the EVA projection, coal is outpaced by natural gas as a share of total generation in 2040, with 2,330 billion kilowatthours from natural gas and 1,740 billion kilowatthours from coal [*147*].

Projections for electricity generation from U.S. nuclear power plants in 2025 range from a low of 794 billion kilowatthours (NREL, in 2026) to a high of 923 billion kilowatthours in the IHSGI projection. NREL projects a steady decline in nuclear generation, from 794 billion kilowatthours in 2025 to 510 billion kilowatthours in 2036 and 442 billion kilowatthours in 2040, due to significant plant retirements. For 2035, the *AEO2013* Reference case projects a drop in nuclear generation from the 2025 level, to 875 billion kilowatthours, as a result of capacity retirements. In contrast, nuclear generation increases to 953 billion kilowatthours in 2035 in the IHSGI projection. The *AEO2013* Reference case shows nuclear generation rebounding to 903 billion kilowatthours in 2040, as compared with 991 billion kilowatthours in the IHSGI projection.

Total generating capacity by fuel in 2025 (including combined heat and power [CHP]) is fairly similar across the projections, ranging from a low of 1,098 gigawatts in the *AEO2013* Reference case to a high of 1,237 gigawatts in the IHSGI projection. IHSGI projects slightly more growth in total generating capacity due to what appears to be a much higher demand projection. Natural gas- and oil-fired capacity combined is projected to total 555 gigawatts in 2025 in the IHSGI projection, compared with 500 gigawatts in the *AEO2013* Reference case and a maximum of 568 gigawatts in the EVA projection. In all the projections, the hydroelectric/other category includes generation from both hydroelectric and nonhydroelectric renewable resources. In all the projections, hydroelectric capacity remains essentially unchanged, with almost all growth attributable to nonhydroelectric renewable resources. Hydroelectric/other capacity is the highest in 2025 in the IHSGI outlook at 289 gigawatts, compared with 257 gigawatts in the NREL projection (for 2026), 234 gigawatts in the ICF projection, 210 gigawatts in the EVA projection, and 208 gigawatts in the *AEO2013* Reference case.

Both the IHSGI and NREL projections reflect lower levels of coal-fired generating capacity in 2040, with 251 gigawatts projected by IHSGI and 224 gigawatts by NREL. In comparison, natural gas- and oil-fired capacity (again dominated by natural gas-fired generating capacity) and hydroelectric/other capacity (dominated by nonhydroeletric renewable capacity) are projected to increase from 2025 levels. IHSGI projects 722 gigawatts of natural gas- and oil-fired capacity and 396 gigawatts of hydroelectric/other capacity in 2040. NREL projects 691 gigawatts of natural gas- and oil-fired capacity and 322 gigawatts of hydroelectric/other capacity in 2040. The *AEO2013* Reference case projects 632 gigawatts of natural gas- and oil-fired capacity and 270 gigawatts of hydroelectric/other capacity in 2040.

Cumulative capacity retirements from 2011 through 2025 range from 151 gigawatts in the EVA projection to 82 gigawatts in the *AEO2013* Reference case. The majority of the retirements in the IHSGI, ICF, and *AEO2013* Reference case projections from 2011 to 2025 are attributed to coal-fired capacity. In the EVA and ICF outlooks, 73 gigawatts of coal-fired capacity is retired from 2011 to 2025. Over the same period, 46 gigawatts of coal-fired capacity is retired in the IHSGI outlook and 49 gigawatts in the *AEO2013* Reference case. The NREL projection assumes 33 gigawatts of coal-fired capacity retirements from 2011 to 2026. EVA projects 73 gigawatts of oil- and natural gas-fired capacity retirements between 2011 and 2025, as compared with the ICF, *AEO2013* Reference case, and IHSGI projections, which range between 29 gigawatts and 36 gigawatts over the same period. NREL projects 69 gigawatts of oil- and natural gas-fired retirements through 2026. With the exception of EVA and ICF, all the capacity retirements greater than 1 gigawatt between 2011 and 2025 in the outlooks are attributed to coal, oil, and natural gas capacity. EVA and ICF both project 3 gigawatts of nuclear retirements by 2025, while EVA projects 2 gigawatts of hydroelectric/other capacity retirements for the same period.

Cumulative capacity retirements through 2035 range from a high of 161 gigawatts in the EVA projection to a low of 100 gigawatts in the *AEO2013* Reference case. Coal-fired capacity represents a large portion of the cumulative retirements from 2011 to 2035, with ICF projecting 82 gigawatts, EVA 77 gigawatts, IHSGI 68 gigawatts, and the *AEO2013* Reference case 49 gigawatts. The *AEO2013* Reference case projects no retirements of coal-fired capacity from 2025 to 2035. Over the same period, EVA projects only 4 gigawatts, ICF 9 gigawatts, and IHSGI 22 gigawatts. Cumulative retirements of oil- and natural gas-fired capacity from 2011 to 2035 total 44 gigawatts in the *AEO2013* Reference case and 74 gigawatts in the EVA projection. NREL projects cumulative totals of 70 gigawatts and 138 gigawatts of retirements for coal-fired capacity and for oil- and natural gas-fired capacity, respectively, from 2011 to 2036. EVA and the *AEO2013* Reference case project cumulative nuclear capacity retirements of 9 gigawatts and 6 gigawatts, respectively, from 2011 to 2035, and IHSGI projects 21 gigawatts of cumulative nuclear retirements over the same period. NREL projects 35 gigawatts of cumulative nuclear retirements from 2011 to 2036.

5. Natural gas

Projections for natural gas consumption, production, imports, and prices differ significantly among the outlooks compared in Table 12. The variations result, in large part, from differences in underlying assumptions. For example, the *AEO2013* Reference case assumes that current laws and regulations are unchanged through the projection period, whereas some of the other projections

Table 12. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted)

Projection	2011	*AEO2013* Reference case	Other projections: IHSGI	EVA	ICF	ExxonMobil	INFORUM
				2025			
Dry gas production[a]	23.00	28.59	32.29	29.86[b]	32.39	--	26.26
Net imports	**1.95**	**-1.58**	**-1.45**	**1.05**	**-0.63**	**--**	**--**
Pipeline	1.67	-0.52	--	2.21	0.60	--	--
LNG	0.28	-1.06	--	-1.16	-1.23	--	--
Consumption	**24.37**	**26.87**	**30.87**	**31.49**	**30.34**[c]	**29.00**[c]	**23.61**[d]
Residential	4.72	4.44	4.58	4.98	5.05	7.00[e]	4.84
Commercial	3.16	3.35	3.23	3.33	3.01	--	3.42
Industrial[f]	6.77	7.82	7.31	8.23	8.79	9.00	7.07
Electricity generators[g]	7.60	8.45	12.57	11.75	10.83	13.00	8.28
Others[h]	2.11	2.81	3.19	3.20	2.66	0.00[i]	--
Henry Hub spot market price (2011 dollars per million Btu)	3.98	4.87	4.39	6.34	5.02	--	--
End-use prices (2011 dollars per thousand cubic feet)							
Residential	11.05	12.97	11.16	--	11.51	--	--
Commercial	9.04	10.43	9.27	--	9.50	--	--
Industrial[j]	5.00	6.29	6.42	--	5.88	--	--
Electricity generators	4.87	5.70	4.89	--	5.85	--	--
				2035			
Dry gas production[a]	23.00	31.35	36.07	31.44[b]	35.46	--	27.91
Net imports	**1.95**	**-2.55**	**-1.18**	**2.62**	**-0.72**	**--**	**--**
Pipeline	1.67	-1.09	--	3.78	0.50	--	--
LNG	0.28	-1.46	--	-1.16	-1.22	--	--
Consumption	**24.37**	**28.71**	**34.90**	**34.67**	**33.14**[c]	**30.00**[c]	**24.45**[d]
Residential	4.72	4.24	4.54	4.96	5.02	7.00[e]	4.72
Commercial	3.16	3.51	3.30	3.47	2.84	--	3.57
Industrial[f]	6.77	8.38	6.85	8.61	9.01	8.00	6.94
Electricity generators[g]	7.60	9.44	16.15	13.98	13.36	15.00	9.23
Others[h]	2.11	3.68	4.06	3.65	2.91	1.00[i]	--
Henry Hub spot market price (2011 dollars per million Btu)	3.98	6.32	4.98	8.00	6.21	--	--
End-use prices (2011 dollars per thousand cubic feet)							
Residential	11.34	15.32	11.58	--	12.28	--	--
Commercial	9.28	12.26	9.78	--	10.38	--	--
Industrial[j]	5.13	7.82	7.02	--	6.98	--	--
Electricity generators	5.00	7.32	5.48	--	7.03	--	--

-- = not reported.
See notes at end of table.

(continued on next page)

include assumptions about anticipated policy developments over the next 25 years. In particular, the *AEO2013* Reference case does not incorporate any future changes in policy directed at carbon emissions or other environmental issues, whereas ExxonMobil and some of the other outlooks include explicit assumptions about policies aimed at reducing carbon emissions.

IHSGI and ICF project large increases in natural gas production and consumption over the projection period. IHSGI projects that, as production increases, prices will remain low and U.S. consumers, particularly in the electric power sector, will continue to benefit from an abundance of relatively inexpensive natural gas. In contrast, ICF projects that prices will rise at a more rapid rate than in the IHSGI projection. EVA projects growth in natural gas production, but at lower rates than IHSGI and ICF. Both EVA and ExxonMobil also project strong growth in natural gas consumption in the electric power sector through 2035. EVA differs from the others, however, by projecting strong growth in natural gas consumption despite a rise in natural gas prices to $8.00 per million Btu in 2035. Timing of the growth in consumption is somewhat different between the ExxonMobil projection and the other outlooks. ExxonMobil expects consumption to increase only through 2025, after which it remains relatively flat. The *AEO2013* Reference case projects a smaller increase in natural gas consumption for electric power generation than in the other outlooks, with additional natural gas production allowing for a sharp increase in net exports, particularly as liquefied natural gas (LNG). The INFORUM projection shows a smaller rise in production and consumption of natural gas than in any of the other projections.

Table 12. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted) (continued)

Projection	2011	*AEO2013* Reference case	Other projections: IHSGI	EVA	ICF	ExxonMobil	INFORUM
		2040					
Dry gas production[a]	23.00	33.14	37.56	--	--	--	--
Net imports	**1.95**	**-3.55**	**-0.95**	**--**	**--**	**--**	**--**
Pipeline	1.67	-2.09	--	--	--	--	--
LNG	0.28	-1.46	--	--	--	--	--
Consumption	**24.37**	**29.54**	**36.61**	**--**	**--**	**30.00[c]**	**--**
Residential	4.72	4.14	4.52	--	--	7.00[e]	--
Commercial	3.16	3.60	3.29	--	--	--	--
Industrial[f]	6.77	7.90	6.68	--	--	8.00	--
Electricity generators[g]	7.60	9.50	17.72	--	--	15.00	--
Others[h]	2.11	4.40	4.40	--	--	1.00[i]	--
Henry Hub spot market price (2011 dollars per million Btu)	3.98	7.83	5.39	--	--	--	--
End-use prices (2011 dollars per thousand cubic feet)							
Residential	11.05	16.74	11.81	--	--	--	--
Commercial	9.04	13.52	10.02	--	--	--	--
Industrial[j]	5.00	9.09	7.32	--	--	--	--
Electricity generators	4.87	8.55	5.83	--	--	--	--

-- = not reported.

Note: Totals may not equal sum of components due to independent rounding.

[a]Does not include supplemental fuels.

[b]Lower 48 only.

[c]Does not include lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[d]Does not include lease, plant, and pipeline fuel.

[e]Natural gas consumed in the residential and commercial sectors.

[f]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power and production; excludes consumption by nonutility generators.

[g]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.

[h]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[i]Fuel consumed in natural gas vehicles only.

[j]The 2011 industrial natural gas price for IHSGI is $6.11.

Production

All the outlooks shown in Table 12 project increases in natural gas production from the 2011 production level of 23.0 trillion cubic feet. IHSGI projects the largest increase, to 36.1 trillion cubic feet in 2035—13.1 trillion cubic feet or 57 percent more than the 2011 levels—with most of the increase coming in the near term (9.3 trillion cubic feet from 2011 to 2025). An additional 1.5 trillion cubic feet of natural gas production is added from 2035 to 2040. In the ICF projection, natural gas production grows by 12.5 trillion cubic feet over the period from 2011, to 35.5 trillion cubic feet in 2035. More than one-half of the increase (6.5 trillion cubic feet) occurs before 2020. INFORUM projects the smallest increase in natural gas production, at only 4.9 trillion cubic feet from 2011 to the 2035 total of 27.9 trillion cubic feet.

The *AEO2013* Reference case and EVA project more modest growth in natural gas production. In the *AEO2013* Reference case and EVA projections, natural gas production grows to 31.4 trillion cubic feet in 2035, an increase of 8.4 trillion cubic feet from 2011 levels. The *AEO2013* Reference case and EVA projections show slower growth in natural gas production from 2011 to 2025, at 5.6 trillion cubic feet and 6.9 trillion cubic feet, respectively. Although the *AEO2013* Reference case shows the least aggressive near-term growth in natural gas production, it shows the strongest growth from 2025 to 2035 among the projections, with another increase of 1.8 trillion cubic feet from 2035 to 2040.

Net imports/exports

Differences among the projections for natural gas production generally coincide with differences in total natural gas consumption or net imports/exports. EVA projects positive growth in net imports throughout the projection period, driven by strong growth in natural gas consumption. Although the EVA projection shows significant growth in pipeline imports, it shows no growth in net LNG exports. In contrast, the IHSGI, ICF, and *AEO2013* Reference case projections show net exports of natural gas starting on or before 2020. The *AEO2013* Reference case projects the largest increase in net exports of natural gas, with net pipeline exports increasing alongside steady growth in net LNG exports. In the ICF projection, the United States becomes a net exporter of natural gas by 2020 but remains a net importer of pipeline through 2035. Combined net exports of natural gas grow to 0.7 trillion cubic feet in 2035 in the ICF projection, with all the growth accounted for by LNG exports, which increase by 1.5 trillion cubic feet from 2011 to 2035. IHSGI projects a U.S. shift from net importer to net exporter of natural gas after 2017, with net exports declining after 2024.

Consumption

All the projections show total natural gas consumption growing throughout the projection periods, and most of them expect the largest increases in the electric power sector. IHSGI projects the greatest growth in natural gas consumption for electric power generation, driven by relatively low natural gas prices, followed by ExxonMobil and EVA, with somewhat higher projections for natural gas prices. The ICF projection shows less growth in natural gas consumption for electric power generation, despite lower natural gas prices, than in the EVA projection. In the *AEO2013* Reference case and INFORUM projections, natural gas consumption for electric power generation is somewhat less than in the other outlooks. Some of that variation may be the result of differences in assumptions about potential fees on carbon emissions. For example, the ExxonMobil outlook assumes a tax on carbon emissions, whereas the *AEO2013* Reference case does not.

Projections for natural gas consumption in the residential and commercial sectors are similar in the outlooks, with expected levels of natural gas use remaining relatively stable over time. The *AEO2013* Reference case projects the lowest level of residential and commercial natural gas consumption, largely as a result of increases in equipment efficiencies, with projected consumption in those sectors falling by 0.1 trillion cubic feet from 2011 to 2040, to a level slightly below those projected by IHSGI and ICF. ExxonMobil projects a significant one-time decrease of 1.0 trillion cubic feet from 2020 to 2025.

The largest difference among the outlooks for natural gas consumption is in the industrial sector, where definitional differences can make accurate comparisons difficult. ExxonMobil and the *AEO2013* Reference case both project increases in natural gas consumption in the industrial sector from 2011 to 2040 that are greater than 1.0 trillion cubic feet, with most of the growth in the *AEO2013* Reference case occurring from 2015 to 2020. ICF projects the largest increase in industrial natural gas consumption, at 2.2 trillion cubic feet from 2011 to 2035, followed by EVA's projection of 1.8 trillion cubic feet over the same period. Although ExxonMobil projects a significant one-time decrease in industrial natural gas consumption—1.0 trillion cubic feet from 2025 to 2030—its projected level of industrial consumption in 2025, at 9.0 trillion cubic feet, is higher than in any of the other projections. Despite ExxonMobil's projected decrease in industrial natural gas consumption from 2025 to 2030, its projection for 2030 (8.0 trillion cubic feet) is second only to EVA's projection of 8.4 trillion cubic feet. IHSGI and INFORUM show modest increases in industrial natural gas consumption from their 2011 levels, to 6.9 trillion cubic feet in 2035 in both outlooks. Projected industrial natural gas consumption declines in the IHSGI projection after 2035, to 6.7 trillion cubic feet in 2040.

Prices

Only four of the outlooks included in Table 12 provide projections for Henry Hub natural gas spot prices. EVA shows the highest Henry Hub prices in 2035 and IHSGI the lowest. In the IHSGI projection, Henry Hub prices remain low through 2035, when they reach $4.98 per million Btu, compared with $3.98 per million Btu in 2011. Natural gas prices to the electric power sector rise from $4.87 per thousand cubic feet in 2011 to $5.47 per thousand cubic feet in 2035 in the IHSGI projection. The low Henry Hub prices in the IHSGI projection are supported by an abundant supply of relatively inexpensive natural gas, with only a small increase in net exports in comparison with the increase in the *AEO2013* Reference case. EVA, in contrast, shows the Henry Hub price rising to a much higher level of $8.00 per million Btu in 2035, apparently as a result of stronger growth in natural gas consumption, particularly for electric power generation, and a lower level of natural gas exports. Indeed, the EVA outlook shows the U.S. remaining a net importer of natural gas through 2035.

Henry Hub natural gas prices in the ICF and *AEO2013* Reference case projections for 2035—at $6.21 per million Btu and $6.32 per million Btu, respectively—fall within the price range bounded by IHSGI and EVA. In the *AEO2013* Reference case, commercial, electric power, and industrial natural gas prices all rise by between $2 and $3 per thousand cubic feet from 2011 to 2035, while residential prices rise by $3.88 per thousand cubic feet over the same period. The residential sector is also the only sector for which the *AEO2013* Reference case projects a decline in natural gas consumption to below 2011 levels in 2035. ICF projects a much smaller increase in delivered natural gas prices for the commercial, industrial, and electric power sectors, with prices rising to more than $2 per thousand cubic feet above 2011 levels by 2035 only in the electric power sector. With smaller price increases, ICF projects a much larger increase for natural gas consumption in the electric power and industrial sectors from 2011 to 2035 than in the *AEO2013* Reference case.

6. Liquid fuels

In the *AEO2013* Reference case, the Brent crude oil spot price (in 2011 dollars) increases to $117 per barrel in 2025, $145 per barrel in 2035, and $163 per barrel in 2040 (Table 13). Prices are higher earlier in the INFORUM and IEA projections but lower in the later years, ranging from $136 per barrel in 2025 to $150 per barrel in 2035. In the *AEO2013* Reference case, the U.S. imported RAC for crude oil (in 2011 dollars) increases to $113 per barrel in 2025, $139 per barrel in 2035, and $155 per barrel in 2040. RAC prices in the INFORUM projection are higher, ranging from $126 per barrel in 2025 to $138 per barrel in 2035. EVA and ExxonMobil did not provide projections for Brent or RAC crude oil prices.

In the *AEO2013* Reference case, domestic crude oil production increases from about 5.7 million barrels per day in 2011 to 6.8 million barrels per day in 2025, then declines to about 6.3 million barrels per day in 2035 and 6.1 million barrels per day in 2040. Overall, projected crude oil production in 2035 is more than 10 percent higher than the 2011 total. The INFORUM projection shows a considerable increase in crude oil production, to 9.5 million barrels per day in 2035. Similarly, the EVA projection shows crude oil production increasing consistently to 8.5 million barrels per day in 2035. The IHSGI projection is closer to the *AEO2013* Reference case, with domestic crude oil production reaching 6.4 million barrels per day in 2035. Similar to the *AEO2013* Reference case, all the outlooks assume continued significant growth in crude oil production from non-OPEC countries, specifically in North America from tight oil formations.

Total net imports of crude oil and other liquids in the *AEO2013* Reference case increase from 8.6 million barrels per day in 2011 to 7.0 million barrels per day in 2025 and remain at that level through the remainder of the projection. The INFORUM projection is similar, at 7.1 million barrels per day in 2025 and 7.4 million barrels per day in 2035. In the IHSGI projection, however, total net imports fall dramatically, to approximately 4.7 million barrels per day in 2035 and around 4.1 million in 2040. IHSGI projects efficiency improvements that would decrease total U.S. demand for liquids and lessen the need for imports.

Biofuel production on a crude oil equivalent basis increases to about 1.1 million barrels per day in both 2025 and in 2035 and to more than 1.3 million barrels per day in 2040 in the *AEO2013* Reference case. IHSGI projects biofuel production of 1.2 million barrels per day in 2025. The IHSGI projection assumes that technology hurdles and economic factors limit the growth of U.S. biofuel production to only a marginal share of total energy supply. IHSGI projects 1.4 million barrels per day of biofuel production in 2035 and a similar level in 2040. The EVA, INFORUM, IEA, and ExxonMobil outlooks do not include biofuels production.

Prices for both diesel fuel and gasoline increase through 2040 in the *AEO2013* Reference case projection, with diesel prices higher than gasoline prices. INFORUM projects increasing gasoline prices and decreasing diesel prices, so that in 2035 the gasoline price is higher than the diesel price. IHSGI projects falling prices for both gasoline and diesel fuel, with 2040 prices for gasoline more than $1.00 per gallon lower and for diesel fuel prices $2.00 per gallon lower than projected in the *AEO2013* Reference case. The EVA, IEA, and ExxonMobil projections do not include delivered fuel prices.

7. Coal

The *AEO2013* Reference case projects the highest levels of total coal production and prices in comparison with other coal outlooks available from EVA, ICF, IHSGI, INFORUM, the IEA's *World Energy Outlook*, and ExxonMobil. Total consumption in *AEO2013* is also higher than in the other outlooks, except for INFORUM and ICF, whose consumption projections for 2035 are 2 percent and 5 percent higher, respectively, than projected in the *AEO2013* Reference case (Table 14).

The detailed assumptions that underlie the various projections are not generally available, although there are some important known differences that contribute to the differences among the outlooks. For instance, EVA and ICF assume the implementation of new regulations for cooling water intake and coal combustion residuals; ExxonMobil, which has the lowest projection of coal consumption, assumes a carbon tax; and ICF also includes a carbon cap-and-trade program beginning in 2023. Because those policies are not current law, the *AEO2013* Reference case excludes them, which contributes to the lower coal consumption

Table 13. Comparisons of liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted)

Projection	2011	*AEO2013* Reference case	EVA	INFORUM[a]	IEA[b,c]	ExxonMobil[a]	IHSGI[a]
				2025			
Average U.S. imported RAC (2011 dollars per barrel)	102.65	113.48	--	126.18	--	--	91.38
Brent spot price (2011 dollars per barrel)	111.26	117.36	78.18	136.77	135.70[c]	--	--
U.S. WTI crude oil price (2011 dollars per barrel)	94.86	115.36	--	--	--	--	93.05
Domestic production	**7.88**	**9.96**	**12.08**	**--**	**--**	**--**	**9.52**
Crude oil	5.67	6.79	8.44	8.57	--	--	6.86
Alaska	0.57	0.35	0.36	--	--	--	--
Natural gas liquids	2.22	3.17	3.64	--	--	--	2.66
Total net imports	**8.58**	**7.01**	**--**	**7.08**	**--**	**--**	**5.98**
Crude oil	8.89	7.05	--	7.08	--	--	7.36
Products	-0.30	-0.04	--	--	--	--	-1.38
Liquids consumption	18.95	19.50	--	18.62	--	19.04	17.59
Net petroleum import share of liquids supplied (percent)	44	37	--	--	--	--	33
Biofuel production	0.97	1.08	--	--	--	--	1.18
Transportation product prices (2011 dollars per gallon)							
Gasoline	3.45	3.49	--	3.97	--	--	3.17
Diesel	3.58	3.97	--	4.00	--	--	3.34
				2035			
Average U.S. imported RAC (2011 dollars per barrel)	102.65	138.70	--	137.97	--	--	84.51
Brent spot price (2011 dollars per barrel)	111.26	145.41	82.16	149.55	145.00[c]	--	--
U.S. WTI crude oil price (2011 dollars per barrel)	94.86	143.41	--	--	--	--	86.25
Domestic production	**7.88**	**9.17**	**12.42**	**--**	**--**	**--**	**9.31**
Crude oil	5.67	6.26	8.50	9.49	--	--	6.43
Alaska	0.57	0.35	0.00	--	--	--	--
Natural gas liquids	2.22	2.91	3.92	--	--	--	2.88
Total net imports	**8.58**	**7.00**	**--**	**7.40**	**--**	**--**	**4.67**
Crude oil	8.89	7.37	--	7.40	--	--	7.03
Products	-0.30	-0.37	--	--	--	--	-2.36
Liquids consumption	18.95	18.86	--	19.24	15.14	18.01	16.07
Net petroleum import share of liquids supplied (percent)	44	36	--	--	--	--	28
Biofuel production	0.97	1.13	--	--	--	--	1.39
Transportation product prices (2011 dollars per gallon)							
Gasoline	3.45	3.94	--	4.14	--	--	2.93
Diesel	3.58	4.55	--	4.06	--	--	3.06

-- = not reported.
See notes at end of table.

(continued on next page)

projections in many of the other outlooks relative to *AEO2013*. Variation among the assumptions about growth in energy demand and other fuel prices, particularly for natural gas, also contribute to the differences.

Although the *AEO2013* projections for total coal consumption are actually somewhat lower than the ICF and INFORUM projections, the other outlooks offer more pessimistic projections. ExxonMobil is the most pessimistic, with coal consumption 33 percent and 55 percent lower in 2025 and 2030, respectively, than in the *AEO2013* Reference case. Coal consumption in 2025 is 17 percent (174 million tons) less in the EVA outlook than in the *AEO2013* Reference case and 8 percent less in the IHSGI outlook. The INFORUM and ICF outlooks for total coal consumption in 2035 are between 21 million tons (2 percent) and 55 million tons (5 percent) higher, respectively, than in the *AEO2013* Reference case.

The electricity sector is the predominant consumer of coal and the primary source of differences among the projections, due to their differing assumptions about regulations and the economics of coal versus other fuel choices over time. Although EVA shows a greater reduction in coal use for electricity generation in 2025 than does IHSGI, for 2035 the two projections are similar. After 2035, EVA shows a continued small increase in coal use for electricity generation, whereas it continues to fall in the IHSGI projection and in 2040 is 37 million tons less than projected by EVA. The ICF outlook for coal consumption in electricity generation is similar to the *AEO2013* projection through 2025 but then declines gradually through 2035. IEA projects a level of coal use for electricity generation in 2035 that is most similar to the *AEO2013* Reference case.

In all the projections, coal consumption in the end-use sectors is low in comparison with the electric power sector; however, there are several notable differences among the outlooks. Most notably, the ICF outlook shows increasing coal use in the other sectors that offsets declining consumption for electric power. ICF is the only projection that shows an increase in coal use in the industrial and buildings sectors. *AEO2013* shows the next highest level of coal consumption in the industrial and buildings sectors, but it is still less than half of ICF's projection for industrial and buildings consumption in 2035. Both IHSGI and EVA show significant declines in coal use in those sectors over the projection period. In 2040, coal use in the buildings and industrial sectors in the IHSGI and EVA

Table 13. Comparisons of liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted) (continued)

Projection	2011	*AEO2013* Reference case	EVA	INFORUM[a]	IEA[b,c]	ExxonMobil[a]	IHSGI[a]
				2040			
Average U.S. imported RAC (2011 dollars per barrel)	102.65	154.96	--	--	--	--	79.46
Brent spot price (2011 dollars per barrel)	111.26	162.68	87.43	--	--	--	--
U.S. WTI crude oil price (2011 dollars per barrel)	94.86	160.68	--	--	--	--	81.20
Domestic production	**7.88**	**9.05**	**--**	**--**	**--**	**--**	**9.31**
Crude oil	5.67	6.13	--	--	--	--	6.43
Alaska	0.57	0.41	--	--	--	--	--
Natural gas liquids	2.22	2.92	--	--	--	--	2.88
Total net imports	**8.58**	**6.91**	**--**	**--**	**--**	**--**	**4.11**
Crude oil	8.89	7.57	--	--	--	--	6.71
Products	-0.30	-0.67	--	--	--	--	-2.60
Liquids consumption	18.95	18.95	--	--	--	17.50	15.48
Net petroleum import share of liquids supplied (percent)	44	35	--	--	--	--	25
Biofuel production	0.97	1.33	--	--	--	--	1.44
Transportation product prices (2011 dollars per gallon)							
Gasoline	3.45	4.32	--	--	--	--	2.78
Diesel	3.58	4.94	--	--	--	--	2.91

-- = not reported.

[a]For INFORUM, ExxonMobil, and IHSGI, liquids demand data were converted from quadrillion Btu to barrels at 187.84572 million barrels per quadrillion Btu.

[b]For IEA, liquids demand data were converted from metric tons to barrels at 8.162674 barrels per metric ton.

[c]IEA crude oil prices represent the international average of crude oil import prices.

Table 14. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted)

Projection	2011	*AEO2013* Reference case (million short tons)	*AEO2013* Reference case (quadrillion Btu)	Other projections: EVA[a] (million short tons)	ICF[b] (million short tons)	IHSGI (million short tons)	INFORUM (million short tons)	IEA (quadrillion Btu)	ExxonMobil[c] (quadrillion Btu)
				2025					
Production	**1,096**	**1,113**	**22.54**	**958**	**1,104**	**1,107**	**1,061**	**--**	**--**
East of the Mississippi	456	447	--	402	445	--	--	--	--
West of the Mississippi	639	666	--	556	659	--	--	--	--
Consumption									
Electric power	929	929	17.66	786	939	864	--	--	13
Coke plants	21	22	0.58	22	15	19	--	--	--
Coal-to-liquids	--	6	--	--	36	--	--	--	--
Other industrial/buildings	49	53	1.69[d]	29	72	44	1.96[d]	--	--
Total consumption (quadrillion Btu)	**19.66**	**--**	**19.35**	**--**	**--**	**18.34**	**--**	**--**	**13**
Total consumption (million short tons)	**999**	**1,010**	**--**	**836**	**1,061**	**927**	**1,015[e]**	**--**	**--**
Net coal exports (million short tons)	**96**	**124**	**--**	**118**	**43**	**181**	**46**	**--**	**--**
Exports	107	129	--	121	123	183	72	--	--
Imports	11	5	--	4	80[f]	2	26	--	--
Minemouth price									
2011 dollars per ton	41.16	52.02	--	--	32.99	--	45.11	--	--
2011 dollars per Btu	2.04	2.60	--	--	1.66	--	2.65	--	--
Average delivered price to electricity generators									
2011 dollars per ton	46.38	51.14	--	--	43.86	46.71[g]	50.83	--	--
2011 dollars per Btu	2.38	2.69	--	--	2.12	2.39	--	--	--
				2035					
Production	**1,096**	**1,171**	**23.60**	**954**	**1,053**	**1,041**	**1,096**	**--**	**--**
East of the Mississippi	456	455	--	397	428	--	--	--	--
West of the Mississippi	639	716	--	558	624	--	--	--	--
Consumption									
Electric power	929	975	18.48	791	919	787	--	18.97[h]	9
Coke plants	21	18	0.48	21	12	18	--	--	--
Coal-to-liquids	--	11	--	--	65	--	--	--	--
Other industrial/buildings	49	53	1.60[d]	24	117	36	2.12[d]	--	--
Total consumption (quadrillion Btu)	**19.66**	**--**	**20.09**	**--**	**--**	**16.55**	**--**	**21.35[h]**	**9**
Total consumption (million short tons)	**999**	**1,058**	**--**	**835**	**1,113**	**841**	**1,079[e]**	**--**	**--**
Net coal exports (million short tons)	**96**	**136**	**--**	**116**	**-61**	**201**	**17**	**--**	**--**
Exports	107	158	--	119	75	203	68	--	--
Imports	11	22	--	4	136[g]	2	51	--	--
Minemouth price									
2010 dollars per ton	41.16	58.57	--	--	30.94	--	--	--	--
2010 dollars per Btu	2.04	2.94	--	--	1.58	--	2.88	--	--
Average delivered price to electricity generators									
2011 dollars per ton	46.38	57.39	--	--	43.24	47.19[g]	55.20	--	--
2011 dollars per Btu	2.38	3.03	--	--	2.12	2.43	--	--	--

-- = not reported.
See notes at end of table.

(continued on next page)

projections is equal to only 39 percent and 60 percent, respectively, of the coal use in those sectors in *AEO2013*. In addition, only *AEO2013* and ICF project coal use for liquids production. Some of the gains in the two sectors are offset in the ICF outlook by lower consumption of coal at coke plants, which falls from 21 million tons in 2011 to 12 million tons in 2035. In the other outlooks, coal use at coke plants is similar to the levels in the *AEO2013* Reference case, with modest declines through the end of their projections.

Differences among the projections for U.S. domestic coal production fall within a smaller range than the projections for coal consumption, depending in part on each outlook's projections for net exports. For example, coal production in the EVA and IHSGI projections is buoyed by relatively high export levels after 2011, with total coal production falling by 13 percent and 5 percent, respectively, from 2011 to 2035, compared with a 16-percent decline in total coal consumption in both projections. The ICF and INFORUM outlooks, which project 11-percent and 8-percent increases in total coal consumption through 2035, respectively, show changes in total coal production of 4 percent and no growth, respectively, as a result of significantly lower net export levels.

The projections for coal exports in the *AEO2013* Reference case generally fall between the EVA and IHSGI projections. INFORUM's projection for coal exports is the lowest among the outlooks but similar to ICF's projection for 2035. The composition of EVA's exports also differs from that in *AEO2013*, in that EVA expects most exports to be thermal coal, whereas most exports in the early

Table 14. Comparisons of coal projections, 2025, 2035, and-2040 (million short tons, except where noted) (continued)

		AEO2013 Reference case		Other projections					
				EVA[a]	ICF[b]	IHSGI	INFORUM	IEA	Exxon-Mobil[c]
Projection	2011	(million short tons)	(quadrillion Btu)	(million short tons)				(quadrillion Btu)	
		2040							
Production	**1,096**	**1,167**	**23.54**	**957**	**--**	**1,015**	**--**	**--**	**--**
East of the Mississippi	456	453	--	396	--	--	--	--	--
West of the Mississippi	639	714	--	561	--	--	--	--	--
Consumption									
Electric power	929	984	18.68	797	--	760	--	--	6
Coke plants	21	18	0.46	19	--	17	--	--	--
Coal-to-liquids	--	14	--	--	--	--	--	--	--
Other industrial/buildings	49	55	1.62[d]	21	--	33	--	--	--
Total consumption (quadrillion Btu)	**19.66**	**--**	**20.35**	**--**	**--**	**15.90**	**--**	**--**	**6**
Total consumption (million short tons)[e]	**999**	**1,071**	**--**	**838**	**--**	**810**	**--**	**--**	**--**
Net coal exports (million short tons)	**96**	**123**	**--**	**116**	**--**	**206**	**--**	**--**	**--**
Exports	107	159	--	119	--	208	--	--	--
Imports	11	36	--	4	--	2	--	--	--
Minemouth price									
2011 dollars per ton	41.16	61.28	--	--	--	--	--	--	--
2011 dollars per Btu	2.04	3.08	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2011 dollars per ton	46.38	60.77	--	--	--	47.70[g]	--	--	--
2011 dollars per Btu	2.38	3.20	--	--	--	2.46	--	--	--

-- = not reported.

[a]Regulations known to be accounted for in the EVA projections include MATS, CAIR, regulations for cooling-water intake structures under Section 316(b) of the Clean Water Act, and regulations for coal combustion residuals under authority of the Resource Conservation and Recovery Act.

[b]Regulations known to be accounted for in the ICF projections include MATS for mercury, HCl and filterables PM requirements starting in 2016, Phase I and II for CAIR followed by a more stringent CAIR replacement in 2018 to address 2012 NAAQS for PM2.5, final state-level mercury restrictions prior to MATS start date and in instances where the state requirement is more stringent than MATS, entrainments requirements for cooling water intake structures beginning in 2025, and coal combustion residual requirements under subtitle D starting in 2018, and a federal carbon cap and trade program starting in 2023.

[c]ExxonMobil projections include a carbon tax.

[d]Coal consumption in quadrillion Btu. INFORUM's value appears to include coal consumption at coke plants. To facilitate comparison, the *AEO2013* value also includes coal consumption at coke plants.

[e]Calculated as imports = (consumption - production + exports).

[f]Calculated as consumption = (production - exports + imports).

[g]Imputed, using heat conversion factor implied by U.S. steam coal consumption data for the electricity sector.

[h]For IEA, data were converted from million tons of oil equivalent using a conversion factor of 39.683 million Btu per ton of oil equivalent.

years of the *AEO2013* Reference case are coking coal. In 2025, coking coal accounts for 57 percent of total coal exports in the *AEO2013* Reference case, compared with 34 percent in the EVA projection. In 2040, however, the coking coal share of exports in the *AEO2013* projection declines to 44 percent, compared with 32 percent in the EVA projection. In comparison, coking coal accounts for 74 percent of total coal exports in 2035 in the ICF projection.

In the EVA and IHSGI projections, coal imports remain low and relatively flat. *AEO2013* also shows low levels of imports initially, but they grow to 36 million tons in 2040 from 5 million tons in 2025. For 2035, the ICF outlook implies 136 million tons of coal imports (calculated by subtracting production from the sum of consumption and exports), which is higher than all the others shown in the comparison table. Coal imports remain above 20 million tons in the INFORUM projections, and as in the ICF and *AEO2013* projections, they increase over time, doubling in 2035 from the 2025 level.

Only *AEO2013*, ICF, and INFORUM provide projections of minemouth coal prices. In the ICF projections, minemouth prices in 2025 are 20 percent below those in 2011 (on a dollar-per-ton basis), and they decline only slightly through 2035. INFORUM projects coal minemouth prices that are very similar to the *AEO2013* prices (on a dollar-per-million Btu basis).

The ICF outlook shows the lowest price for coal delivered to the electricity sector in both 2025 and 2035, with the real coal price lower than in 2011. INFORUM's prices for coal delivered to electricity generators (on a dollar-per-ton basis) are similar. IHSGI's delivered coal prices to electricity generators are significantly lower than those in the *AEO2013* Reference case and remain close to the 2011 price over the entire projection period. As a result, the IHSGI delivered coal price to electricity generators is 9 percent lower in 2025 and 22 percent lower in 2040, on a dollar-per-ton basis, than projected in the *AEO2013* Reference case.

Endnotes for Comparison with other projections

Links current as of March 2013

145. EIA summed the sector-level sales from the INFORUM and EVA projections to develop a total electricity sales value for comparison purposes.
146. EIA estimated a weighted-average electricity price for INFORUM based on the sector-level prices and sales.
147. For purposes of comparison, generation from natural gas, turbine, and oil/gas steam capacity from EVA was combined, resulting in a total of 2,330 billion kilowatthours of generation from natural gas for 2040, as shown in Table 25.

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List of acronyms

AB 32	California Assembly Bill 32
ACP	Alternative compliance payment
AEO	*Annual Energy Outlook*
AEO2012	*Annual Energy Outlook 2012*
AEO2013	*Annual Energy Outlook 2013*
API	American Petroleum Institute
ARRA2009	American Recovery and Reinvestment Act of 2009
ATRA	American Taxpayer Relief Act of 2012
Blue Chip	Blue Chip Consensus
BTL	Biomass-to-liquids
Btu	British thermal units
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CBO	Congressional Budget Office
CBTL	Coal- and biomass-to-liquids
CCS	Carbon capture and storage
CHP	Combined heat and power
CMM	Coal Market Module
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COL	Combined license
CO_2-EOR	Carbon dioxide-enhanced oil recovery
CSAPR	Cross-State Air Pollution Rule
CTL	Coal-to-liquids
DG	Distributed generation
DOE	U.S. Department of Energy
DSI	Dry sorbent injection
E10	Motor gasoline blend containing up to 10 percent ethanol
E15	Motor gasoline blend containing up to 15 percent ethanol
E85	Motor fuel containing up to 85 percent ethanol
EIA	U.S. Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EMM	Electricity Market Module
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT2005	Energy Policy Act of 2005
EUR	Estimated ultimate recovery
EVA	Energy Ventures Analysis
FCC	Fluid catalytic cracking
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
HAP	Hazardous air pollutant
HDV	Heavy-duty vehicle
Hg	Mercury
ICF	ICF International
IDM	Industrial Demand Module
IEA	International Energy Agency
IEM	International Energy Module
IHSGI	IHS Global Insight, Inc.
INFORUM	Interindustry Forecasting Project at the University of Maryland
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicle
LED	Light-emitting diode
LFG	Landfill gas
LFMM	Liquid Fuels Market Module
LNG	Liquefied natural gas
LPG	Liquefied petroleum gases
MACT	Maximum achievable control technology
MATS	Mercury and Air Toxics Standards
MAM	Macroeconomic Activity Module
$MMTCO_2e$	Million metric tons carbon dioxide equivalent
mpg	Miles per gallon
MY	Model year
MSW	Municipal solid waste
NAICS	North American Industry Classification System
NEMS	National Energy Modeling System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGCC	Natural gas combined-cycle
NGL	Natural gas liquids
NGPL	Natural gas plant liquids
NGTDM	Natural Gas Transmission and Distribution Module
NHTSA	National Highway Traffic Safety Administration
NO_X	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OECD	Organization for Economic Cooperation and Development
OEG	Oxford Economics Group
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
PADDs	Petroleum Administration for Defense Districts
PCs	Personal computers
PM	Particulate matter
PTC	Production tax credit
PV	Solar photovoltaic
RAC	U.S. refiner acquisition cost
RFM	Renewable Fuels Module
RFS	Renewable fuel standard
RPS	Renewable portfolio standard
SCR	Selective catalytic reduction
SMR	Small modular reactor
SNCR	Selective noncatalytic reduction
SONGS	San Onofre Nuclear Generating Station
SO_2	Sulfur dioxide
SSA	Social Security Administration
STEO	*Short-Term Energy Outlook*
TRR	Technically recoverable resource
TVA	Tennessee Valley Authority
VMT	Vehicle miles traveled
WTI	West Texas Intermediate

Notes and sources

Table notes and sources

Legislation and regulations

Table 1. NHTSA projected average fleet-wide CAFE compliance levels for passenger cars and light-duty trucks, model years 2017-2025, based on the model year 2010 baseline fleet: U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register,* Vol. 77, No. 199 (Washington, DC, October 15, 2012), https://federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.

Table 2. *AEO2013* projected average fleet-wide CAFE compliance levels for passenger cars and light-duty trucks, model years 2017-2025: AEO2013 National Energy Modeling System, run REF2013.D102312A.

Table 3. Renewable portfolio standards in the 30 States and District of Columbia with current mandates: U.S. Energy Information Administration, Office of Energy Analysis. Based on a review of enabling legislation and regulatory actions from the various States of policies identified by the Database of States Incentives for Renewable Energy as of December 15, 2012, http://www.dsireusa.org.

Issues in focus

Table 4. Key analyses from "Issues in focus" in recent *AEO*s: U.S. Energy Information Administration, *Annual Energy Outlook 2012,* DOE/EIA-0383(2012) (Washington, DC, June 2012); U.S. Energy Information Administration, *Annual Energy Outlook 2011,* DOE/EIA-0383(2011) (Washington, DC, April 2011); and U.S. Energy Information Administration, *Annual Energy Outlook 2010,* DOE/EIA-0383(2010) (Washington, DC, April 2010).

Table 5. Differences in crude oil and natural gas assumptions across three cases: AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D011813A, and HIGHRESOURCE.D021413A.

Table 6. Differences in transportation demand assumptions across three cases: AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWIMPORT.D021113B, and HIGHIMPORT.D012813A.

Table 7. Proposed U.S. ethylene production capacity, 2013-2020: Stephen Zinger et. al., "A Renaissance for U.S. Gas-Intensive Industries Part 2," Wood Mackenzie (November 2012).

Comparison with other projections

Table 8. Projections of average annual economic growth, 2011-2040: *AEO2013* (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. ***AEO2012* (Reference case):** AEO2012 National Energy Modeling System, run AEO2012.REF2012.D020112C. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **OMB:** Office of Management and Budget, *Fiscal Year 2013 Budget of the U.S. Government* (Washington, DC, January 2013), http://www.whitehouse.gov/sites/default/files/omb/budget/fy2013/assets/budget.pdf. **CBO:** Congressional Budget Office, The Budget and Economic Outlook: Fiscal Years 2012 to 2022 (Washington, DC, February 2013), http://www.cbo.gov/publication/42905. **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **SSA:** Social Security Administration, *The 2012 Annual Report of the Board of Trustees of the Federal Old-Age And Survivors Insurance and Federal Disability Insurance Trust Funds* (U.S. Government Printing Office, Washington, DC, April 23 2012), http://www.ssa.gov/oact/tr/2012/2012_Long-Range_Economic_Assumptions.pdf. **IEA (2012):** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org. **Blue Chip Consensus:** *Blue Chip Economic Indicators* (Aspen Publishers, October 2012), http://www.aspenpublishers.com/Topics/Banking-Law-Finance-Economic-Forecast/. **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **ICF:** "ICF Integrated Energy Outlook Q4 2012," ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 4th Quarter, 2012). **Oxford Economics Group:** Oxford Economics, Ltd., 2013 Long Term Forecast (Oxford, United Kingdom, January 2013), http://www.OxfordEconomics.com (subscription site).

Table 9. Projections of oil prices, 2025, 2035, and 2040: *AEO2013* (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. ***AEO2012* (Reference case):** AEO2012 National Energy Modeling System, run AEO2012.REF2012.D020112C. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **IEA (Current Policies Scenario):** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org. **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site).

Table 10. Projections of energy consumption by sector, 2025, 2035, and 2040: *AEO2013* (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **IEA:** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org.

Table 11. Comparison of electricity projections, 2025, 2035, and 2040: *AEO2013* (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **ICF:** "ICF Integrated Energy Outlook Q4 2012," ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 4th Quarter 2012. **NREL:** National Renewable Energy Laboratory, e-mail from Trieu Mai (January 14, 2013).

Table 12. Comparison of natural gas projections, 2025, 2035, and 2040: *AEO2013* (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **ICF:** "ICF Integrated Energy Outlook Q4 2012," ICF Integrated Planning Model (IPM) and Gas Market Model (GMM)" (Fairfax, VA, 4th Quarter 2012). **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html.

Table 13. Comparison of liquids projections, 2025, 2035, and 2040: *AEO2013* (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **IEA:** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org. **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx.

Table 14. Comparison of coal projections, 2025, 2035, and 2040: *AEO2013* (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **ICF:** "ICF Integrated Energy Outlook Q4 2012," ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 4th Quarter 2012). **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **IEA:** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org. **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx.

Figure notes and sources

Executive summary

Figure 1. Net import share of U.S. liquids supply in two cases, 1970-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). Projections: AEO2013 National Energy Modeling System, runs REF2013.D102312A and LOWIMPORT.D021113A.

Figure 2. Total U.S. natural gas production, consumption, and net imports, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). Projections: AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 3. Power sector electricity generation from coal and natural gas in two cases, 2008-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A and HIGHRESOURCE.D021413A.

Figure 4. Coal and natural gas use in the electric power sector in three cases, 2011, 2025, and 2040: 2011: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHRESOURCE.D021413A, and CO2FEE15.D021413A.

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Figure 93. Consumption of petroleum and other liquids by sector, 1990-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 94. U.S. production of petroleum and other liquids by source, 2011-2040: Projections: AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 95. Total U.S. crude oil production in three resource cases, 1990-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

Figure 96. Domestic crude oil production by source, 2000-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011), Table 5.2, (Washington, DC, September 2011). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 97. Total U.S. tight oil production by geologic formation, 2008-2040: History: Drilling Info (formerly HPDI), Texas RRC, North Dakota department of mineral resources. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 98. API gravity of U.S. domestic and imported crude oil supplies, 1990-2040: History: U.S. Energy Information Administration, Crude Oil Input Qualities and Company Level Imports Archives, http://www.eia.gov/petroleum/imports/companylevel/archive/. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 99. Net import share of U.S. petroleum and other liquids consumption in three oil price cases, 1990-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWPRICE.D031213A, and HIGHPRICE.D110912A.

Figure 100. EISA2007 RFS credits earned in selected years, 2011-2040: Projections: AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 101. Consumption of advanced renewable fuels, 2011-2040: Projections: AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 102. U.S. motor gasoline and diesel fuel consumption, 2000-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 103. U.S. refinery gasoline-to-diesel production ratio and crack spread, 2008-2040: History: 2008-2010: Crack spread calculated from national average wholesale prices for diesel fuel and gasoline blend components (RBOB) and historical crude prices. Wholesale prices calculated from historical end use prices and distributor/tax markups. Oil and Gas Information Reporting System (OGIRS). **2011:** U.S. Energy Information Administration, *EIA Today In Energy* (October 31, 2011), "3:2:1 crack spreads based on WTI & LLS crude oils have diverged in 2011," http://www.eia.gov/todayinenergy/detail.cfm?id=3710. **2008-2011:** Gasoline and diesel refinery production calculated as the difference of historical consumption levels and corresponding non-petroleum components (ethanol, biodiesel). Oil and Gas Information Reporting System (OGIRS). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 104. Coal production by region, 1970-2040: History (short tons): 1970-1990: U.S. Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change,* DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** U.S. Energy Information Administration, *Coal Industry Annual,* DOE/EIA-0584 (various years). **2001-2011:** U.S. Energy Information Administration, *Annual Coal Report 2011,* DOE/EIA-0584(2011) (Washington, DC, November 2012), and previous issues. **History (conversion to quadrillion Btu): 1970-2010: Estimation Procedure:** Estimates of average heat content by region and year are based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Annual Energy Review.* **Sources:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Annual Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A. **Note:** For 1989-2035, coal production includes waste coal.

Figure 105. U.S. total coal production in six cases, 2011, 2020, and 2040: Projections: AEO2013 National Energy Modeling System, runs REF2013.D102312A, LCCST13.D112112A, HCCST13.D112112A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, and CO2FEE15.D021413A. **Note:** Coal production includes waste coal.

Figure 106. Average annual minemouth coal prices by region, 1990-2040: History (dollars per short ton): 1990-2000: U.S. Energy Information Administration, *Coal Industry Annual,* DOE/EIA-0584 (various years). **2001-2011:** U.S. Energy Information Administration, *Annual Coal Report 2011,* DOE/EIA-0584(2011) (Washington, DC, November 2012), and previous issues. **History (conversion to dollars per million Btu): 1970-2011: Estimation Procedure:** Estimates of average heat content by region and year based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Annual Energy Review.* **Sources:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Annual Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A. **Note:** Includes reported prices for both open-market and captive mines.

Figure 107. Cumulative coal-fired generating capacity additions and environmental retrofits in two cases, 2012-2040: Projections: AEO2013 National Energy Modeling System, runs REF2013.D102312A and NOGHGCONCERN.D110912A.

Figure 108. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* March, 2013, DOE/EIA-0035(2013/03). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 109. Sulfur dioxide emissions from electricity generation, 1990-2040: History: U.S. Environmental Protection Agency, *Clean Air Interstate Rule, Acid Rain Program, and Former NO_X Budget Trading Program 2011 Progress Report,* http://www.epa.gov/airmarkets/progress/ARPCAIR11_01.html#qualityassurance. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 110. Nitrogen oxides emissions from electricity generation, 1990-2040: History: U.S. Environmental Protection Agency, *Clean Air Interstate Rule, Acid Rain Program, and Former NO_X Budget Trading Program 2011 Progress Report,* http://www.epa.gov/airmarkets/progress/ARPCAIR11_01.html#qualityassurance. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

Figure 111. Energy-related carbon dioxide emissions in two cases with three levels of emissions fees, 2000-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHRESOURCE.D021413A, CO2FEE10.D021413A, CO2FEE15.D021413A, CO2FEE25.D021413A, CO2FEE10HR.D021413A, CO2FEE15HR.D021413A, and CO2FEE25HR.D021413A.

Figure 112. Natural gas-fired electricity generation in six CO_2 fee cases, 2000-2040: History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHRESOURCE.D021413A, CO2FEE10.D021413A, CO2FEE15.D021413A, CO2FEE25.D021413A, CO2FEE10HR.D021413A, CO2FEE15HR.D021413A, and CO2FEE25HR.D021413A.

Table A1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Production								
Crude oil and lease condensate	11.59	12.16	15.95	14.50	13.47	13.40	13.12	0.3%
Natural gas plant liquids	2.78	2.88	4.14	4.20	3.85	3.87	3.89	1.0%
Dry natural gas	21.82	23.51	27.19	29.22	30.44	32.04	33.87	1.3%
Coal[1]	22.04	22.21	21.74	22.54	23.25	23.60	23.54	0.2%
Nuclear / uranium[2]	8.43	8.26	9.25	9.54	9.49	9.14	9.44	0.5%
Hydropower	2.54	3.17	2.83	2.86	2.87	2.90	2.92	-0.3%
Biomass[3]	4.05	4.05	5.00	5.27	5.42	5.83	6.96	1.9%
Other renewable energy[4]	1.31	1.58	2.22	2.32	2.50	2.91	3.84	3.1%
Other[5]	0.76	1.20	0.83	0.85	0.88	0.90	0.89	-1.0%
Total	**75.31**	**79.02**	**89.16**	**91.29**	**92.18**	**94.59**	**98.46**	**0.8%**
Imports								
Crude oil	20.14	19.46	15.02	15.57	16.33	16.43	16.89	-0.5%
Liquid fuels and other petroleum[6]	5.26	5.24	5.55	5.47	5.33	5.13	4.82	-0.3%
Natural gas[7]	3.83	3.54	2.58	2.36	2.63	2.53	2.01	-1.9%
Other imports[8]	0.52	0.43	0.11	0.17	0.13	0.48	0.84	2.4%
Total	**29.75**	**28.66**	**23.26**	**23.57**	**24.41**	**24.57**	**24.55**	**-0.5%**
Exports								
Liquid fuels and other petroleum[9]	4.86	6.08	5.37	5.14	5.25	5.55	5.71	-0.2%
Natural gas[10]	1.15	1.52	2.67	3.92	4.71	5.07	5.56	4.6%
Coal	2.10	2.75	3.13	3.18	3.51	3.80	3.79	1.1%
Total	**8.11**	**10.35**	**11.17**	**12.25**	**13.47**	**14.42**	**15.06**	**1.3%**
Discrepancy[11]	**-1.40**	**-0.36**	**0.21**	**0.27**	**0.30**	**0.32**	**0.32**	**- -**
Consumption								
Liquid fuels and other petroleum[12]	37.76	37.02	37.54	36.87	36.08	35.82	36.07	-0.1%
Natural gas	24.32	24.91	26.77	27.28	27.95	29.06	29.83	0.6%
Coal[13]	20.81	19.66	18.59	19.35	19.70	20.09	20.35	0.1%
Nuclear / uranium[2]	8.43	8.26	9.25	9.54	9.49	9.14	9.44	0.5%
Hydropower	2.54	3.17	2.83	2.86	2.87	2.90	2.92	-0.3%
Biomass[14]	2.87	2.74	3.53	3.82	3.94	4.23	4.91	2.0%
Other renewable energy[4]	1.31	1.58	2.22	2.32	2.50	2.91	3.84	3.1%
Other[15]	0.31	0.35	0.31	0.30	0.28	0.26	0.29	-0.6%
Total	**98.35**	**97.70**	**101.04**	**102.34**	**102.81**	**104.41**	**107.64**	**0.3%**
Prices (2011 dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	81.31	111.26	105.57	117.36	130.47	145.41	162.68	1.3%
West Texas Intermediate	81.08	94.86	103.57	115.36	128.47	143.41	160.68	1.8%
Natural gas at Henry Hub (dollars per million Btu)	4.46	3.98	4.13	4.87	5.40	6.32	7.83	2.4%
Coal (dollars per ton)								
at the minemouth[16]	36.37	41.16	49.26	52.02	55.64	58.57	61.28	1.4%
Coal (dollars per million Btu)								
at the minemouth[16]	1.80	2.04	2.45	2.60	2.79	2.94	3.08	1.4%
Average end-use[17]	2.42	2.57	2.77	2.94	3.10	3.25	3.42	1.0%
Average electricity (cents per kilowatthour)	10.0	9.9	9.4	9.5	9.7	10.1	10.8	0.3%

Table A1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Prices (nominal dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	79.61	111.26	121.73	147.90	180.04	219.73	268.50	3.1%
West Texas Intermediate	79.39	94.86	119.43	145.38	177.28	216.70	265.20	3.6%
Natural gas at Henry Hub (dollars per million Btu)	4.37	3.98	4.77	6.14	7.45	9.55	12.92	4.1%
Coal (dollars per ton)								
at the minemouth[16]	35.61	41.16	56.81	65.55	76.78	88.51	101.14	3.1%
Coal (dollars per million Btu)								
at the minemouth[16]	1.76	2.04	2.83	3.27	3.85	4.44	5.08	3.2%
Average end-use[17]	2.37	2.57	3.19	3.70	4.28	4.92	5.65	2.8%
Average electricity (cents per kilowatthour)	9.8	9.9	10.8	12.0	13.4	15.2	17.8	2.0%

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2010 and 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2010 and 2011 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012). 2011 petroleum supply values and 2010 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). Other 2010 petroleum supply values: EIA, *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2010 and 2011 crude oil spot prices: Thomson Reuters. Other 2010 and 2011 coal values: *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012). Other 2010 and 2011 values: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Energy consumption								
Residential								
Propane	0.53	0.53	0.52	0.52	0.52	0.52	0.52	-0.0%
Kerosene	0.03	0.02	0.01	0.01	0.01	0.01	0.01	-1.8%
Distillate fuel oil	0.58	0.59	0.51	0.45	0.40	0.36	0.32	-2.1%
Liquid fuels and other petroleum subtotal	1.14	1.14	1.05	0.98	0.93	0.89	0.86	-1.0%
Natural gas	4.89	4.83	4.62	4.54	4.46	4.34	4.23	-0.5%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.00	-0.9%
Renewable energy[1]	0.44	0.45	0.44	0.44	0.45	0.45	0.45	0.1%
Electricity	4.93	4.86	4.84	5.08	5.36	5.67	6.03	0.7%
Delivered energy	**11.41**	**11.28**	**10.95**	**11.04**	**11.20**	**11.35**	**11.57**	**0.1%**
Electricity related losses	10.35	10.20	9.66	10.04	10.45	10.90	11.50	0.4%
Total	**21.76**	**21.48**	**20.62**	**21.08**	**21.65**	**22.25**	**23.08**	**0.2%**
Commercial								
Propane	0.14	0.14	0.16	0.16	0.16	0.17	0.17	0.7%
Motor gasoline[2]	0.06	0.05	0.05	0.06	0.06	0.06	0.06	0.5%
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.01	2.1%
Distillate fuel oil	0.41	0.42	0.34	0.33	0.32	0.31	0.30	-1.1%
Residual fuel oil	0.08	0.07	0.09	0.09	0.09	0.09	0.09	0.6%
Liquid fuels and other petroleum subtotal	0.69	0.69	0.65	0.64	0.64	0.63	0.63	-0.3%
Natural gas	3.17	3.23	3.40	3.43	3.50	3.59	3.68	0.4%
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05	-0.0%
Renewable energy[3]	0.11	0.13	0.13	0.13	0.13	0.13	0.13	0.0%
Electricity	4.54	4.50	4.72	4.97	5.22	5.47	5.72	0.8%
Delivered energy	**8.57**	**8.60**	**8.95**	**9.22**	**9.54**	**9.86**	**10.21**	**0.6%**
Electricity related losses	9.52	9.45	9.42	9.82	10.18	10.51	10.92	0.5%
Total	**18.09**	**18.05**	**18.37**	**19.04**	**19.72**	**20.37**	**21.13**	**0.5%**
Industrial[4]								
Liquefied petroleum gases	2.12	2.10	2.46	2.54	2.47	2.40	2.30	0.3%
Propylene	0.41	0.40	0.56	0.56	0.52	0.49	0.46	0.6%
Motor gasoline[2]	0.28	0.27	0.32	0.32	0.32	0.32	0.32	0.6%
Distillate fuel oil	1.19	1.21	1.22	1.19	1.18	1.19	1.22	0.0%
Residual fuel oil	0.12	0.11	0.11	0.11	0.11	0.11	0.11	-0.1%
Petrochemical feedstocks	0.94	0.88	1.03	1.08	1.08	1.08	1.09	0.7%
Other petroleum[5]	3.70	3.61	3.54	3.48	3.46	3.53	3.65	0.0%
Liquid fuels and other petroleum subtotal	8.76	8.57	9.25	9.28	9.14	9.11	9.16	0.2%
Natural gas	6.67	6.92	7.86	8.00	7.97	8.02	8.08	0.5%
Natural-gas-to-liquids heat and power	0.00	0.00	0.13	0.16	0.21	0.27	0.33	- -
Lease and plant fuel[6]	1.31	1.42	1.57	1.68	1.73	1.84	1.97	1.1%
Natural gas subtotal	7.98	8.34	9.56	9.84	9.91	10.13	10.38	0.8%
Metallurgical coal	0.55	0.56	0.60	0.58	0.52	0.48	0.46	-0.7%
Other industrial coal	1.06	1.04	1.00	1.00	1.00	1.02	1.05	0.0%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.07	0.09	0.12	0.15	- -
Net coal coke imports	-0.01	0.01	-0.01	-0.03	-0.04	-0.06	-0.05	- -
Coal subtotal	1.60	1.62	1.58	1.63	1.57	1.56	1.61	-0.0%
Biofuels heat and coproducts	0.85	0.67	0.82	0.82	0.85	0.97	1.37	2.5%
Renewable energy[7]	1.47	1.51	1.72	1.85	1.97	2.11	2.28	1.4%
Electricity	3.31	3.33	3.95	4.05	3.96	3.90	3.91	0.6%
Delivered energy	**23.98**	**24.04**	**26.87**	**27.46**	**27.40**	**27.77**	**28.71**	**0.6%**
Electricity related losses	6.95	6.99	7.89	8.00	7.72	7.49	7.45	0.2%
Total	**30.93**	**31.03**	**34.76**	**35.46**	**35.11**	**35.26**	**36.16**	**0.5%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Transportation								
Propane	0.04	0.06	0.06	0.06	0.07	0.08	0.08	1.3%
E85[8]	0.01	0.05	0.08	0.14	0.16	0.15	0.17	4.3%
Motor gasoline[2]	16.79	16.31	14.88	13.86	13.06	12.69	12.64	-0.9%
Jet fuel[9]	3.07	3.01	3.11	3.20	3.28	3.35	3.42	0.4%
Distillate fuel oil[10]	5.82	5.91	7.28	7.52	7.61	7.73	7.90	1.0%
Residual fuel oil	0.88	0.82	0.84	0.85	0.86	0.86	0.87	0.2%
Other petroleum[11]	0.17	0.17	0.15	0.15	0.16	0.16	0.16	-0.1%
Liquid fuels and other petroleum subtotal	26.78	26.32	26.42	25.79	25.20	25.01	25.24	-0.1%
Pipeline fuel natural gas	0.68	0.70	0.71	0.73	0.74	0.76	0.78	0.4%
Compressed / liquefied natural gas	0.04	0.04	0.08	0.12	0.26	0.60	1.05	11.9%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	0.02	0.02	0.03	0.04	0.04	0.06	0.07	3.9%
Delivered energy	**27.52**	**27.09**	**27.24**	**26.68**	**26.25**	**26.43**	**27.14**	**0.0%**
Electricity related losses	0.05	0.05	0.06	0.07	0.09	0.11	0.13	3.5%
Total	**27.57**	**27.13**	**27.30**	**26.75**	**26.33**	**26.54**	**27.27**	**0.0%**
Delivered energy consumption for all sectors								
Liquefied petroleum gases	2.83	2.82	3.21	3.29	3.23	3.16	3.08	0.3%
Propylene	0.41	0.40	0.56	0.56	0.52	0.49	0.46	0.6%
E85[8]	0.01	0.05	0.08	0.14	0.16	0.15	0.17	4.3%
Motor gasoline[2]	17.13	16.64	15.26	14.24	13.43	13.07	13.03	-0.8%
Jet fuel[9]	3.07	3.01	3.11	3.20	3.28	3.35	3.42	0.4%
Kerosene	0.04	0.03	0.03	0.03	0.02	0.02	0.02	-0.3%
Distillate fuel oil	8.00	8.12	9.35	9.49	9.51	9.58	9.74	0.6%
Residual fuel oil	1.08	1.01	1.05	1.05	1.05	1.06	1.07	0.2%
Petrochemical feedstocks	0.94	0.88	1.03	1.08	1.08	1.08	1.09	0.7%
Other petroleum[12]	3.86	3.77	3.69	3.63	3.61	3.68	3.80	0.0%
Liquid fuels and other petroleum subtotal	37.37	36.72	37.37	36.69	35.90	35.64	35.88	-0.1%
Natural gas	14.77	15.03	15.95	16.08	16.19	16.54	17.05	0.4%
Natural-gas-to-liquids heat and power	0.00	0.00	0.13	0.16	0.21	0.27	0.33	- -
Lease and plant fuel[6]	1.31	1.42	1.57	1.68	1.73	1.84	1.97	1.1%
Pipeline natural gas	0.68	0.70	0.71	0.73	0.74	0.76	0.78	0.4%
Natural gas subtotal	16.77	17.15	18.36	18.66	18.87	19.42	20.13	0.6%
Metallurgical coal	0.55	0.56	0.60	0.58	0.52	0.48	0.46	-0.7%
Other coal	1.12	1.10	1.06	1.06	1.06	1.07	1.11	0.0%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.07	0.09	0.12	0.15	- -
Net coal coke imports	-0.01	0.01	-0.01	-0.03	-0.04	-0.06	-0.05	- -
Coal subtotal	1.67	1.67	1.64	1.69	1.63	1.61	1.67	-0.0%
Biofuels heat and coproducts	0.85	0.67	0.82	0.82	0.85	0.97	1.37	2.5%
Renewable energy[13]	2.01	2.08	2.28	2.42	2.54	2.68	2.86	1.1%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.81	12.71	13.54	14.13	14.59	15.08	15.72	0.7%
Delivered energy	**71.49**	**71.01**	**74.01**	**74.40**	**74.38**	**75.41**	**77.63**	**0.3%**
Electricity related losses	26.86	26.69	27.03	27.94	28.43	29.00	30.00	0.4%
Total	**98.35**	**97.70**	**101.04**	**102.34**	**102.81**	**104.41**	**107.64**	**0.3%**
Electric power[14]								
Distillate fuel oil	0.08	0.06	0.08	0.08	0.08	0.08	0.08	0.9%
Residual fuel oil	0.31	0.23	0.10	0.10	0.10	0.10	0.11	-2.6%
Liquid fuels and other petroleum subtotal	0.39	0.30	0.18	0.18	0.18	0.18	0.19	-1.6%
Natural gas	7.55	7.76	8.40	8.63	9.08	9.64	9.70	0.8%
Steam coal	19.13	17.99	16.95	17.66	18.07	18.48	18.68	0.1%
Nuclear / uranium[15]	8.43	8.26	9.25	9.54	9.49	9.14	9.44	0.5%
Renewable energy[16]	3.85	4.74	5.49	5.77	5.93	6.38	7.44	1.6%
Electricity imports	0.09	0.13	0.08	0.07	0.05	0.03	0.06	-2.4%
Total[17]	**39.67**	**39.40**	**40.57**	**42.07**	**43.02**	**44.08**	**45.73**	**0.5%**

Table A2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Total energy consumption								
Liquefied petroleum gases	2.83	2.82	3.21	3.29	3.23	3.16	3.08	0.3%
Propylene	0.41	0.40	0.56	0.56	0.52	0.49	0.46	0.6%
E85[8]	0.01	0.05	0.08	0.14	0.16	0.15	0.17	4.3%
Motor gasoline[2]	17.13	16.64	15.26	14.24	13.43	13.07	13.03	-0.8%
Jet fuel[9]	3.07	3.01	3.11	3.20	3.28	3.35	3.42	0.4%
Kerosene	0.04	0.03	0.03	0.03	0.02	0.02	0.02	-0.3%
Distillate fuel oil	8.08	8.18	9.43	9.57	9.59	9.66	9.82	0.6%
Residual fuel oil	1.38	1.24	1.15	1.15	1.15	1.16	1.17	-0.2%
Petrochemical feedstocks	0.94	0.88	1.03	1.08	1.08	1.08	1.09	0.7%
Other petroleum[12]	3.86	3.77	3.69	3.63	3.61	3.68	3.80	0.0%
Liquid fuels and other petroleum subtotal	37.76	37.02	37.54	36.87	36.08	35.82	36.07	-0.1%
Natural gas	22.32	22.79	24.36	24.71	25.27	26.18	26.75	0.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.13	0.16	0.21	0.27	0.33	- -
Lease and plant fuel[6]	1.31	1.42	1.57	1.68	1.73	1.84	1.97	1.1%
Pipeline natural gas	0.68	0.70	0.71	0.73	0.74	0.76	0.78	0.4%
Natural gas subtotal	24.32	24.91	26.77	27.28	27.95	29.06	29.83	0.6%
Metallurgical coal	0.55	0.56	0.60	0.58	0.52	0.48	0.46	-0.7%
Other coal	20.26	19.09	18.01	18.72	19.12	19.55	19.79	0.1%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.07	0.09	0.12	0.15	- -
Net coal coke imports	-0.01	0.01	-0.01	-0.03	-0.04	-0.06	-0.05	- -
Coal subtotal	20.81	19.66	18.59	19.35	19.70	20.09	20.35	0.1%
Nuclear / uranium[15]	8.43	8.26	9.25	9.54	9.49	9.14	9.44	0.5%
Biofuels heat and coproducts	0.85	0.67	0.82	0.82	0.85	0.97	1.37	2.5%
Renewable energy[18]	5.86	6.82	7.77	8.18	8.47	9.07	10.30	1.4%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity imports	0.09	0.13	0.08	0.07	0.05	0.03	0.06	-2.4%
Total	**98.35**	**97.70**	**101.04**	**102.34**	**102.81**	**104.41**	**107.64**	**0.3%**
Energy use and related statistics								
Delivered energy use	71.49	71.01	74.01	74.40	74.38	75.41	77.63	0.3%
Total energy use	98.35	97.70	101.04	102.34	102.81	104.41	107.64	0.3%
Ethanol consumed in motor gasoline and E85	1.11	1.17	1.34	1.29	1.24	1.20	1.21	0.1%
Population (millions)	310.06	312.38	340.45	356.46	372.41	388.35	404.39	0.9%
Gross domestic product (billion 2005 dollars)	13,063	13,299	16,859	18,985	21,355	24,095	27,277	2.5%
Carbon dioxide emissions (million metric tons)	5,633.6	5,470.7	5,454.6	5,501.4	5,522.8	5,606.7	5,691.1	0.1%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2012. 2010 and 2011 carbon dioxide emissions: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 carbon dioxide emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/10) (Washington, DC, October 2011). 2011 carbon dioxide emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A3. Energy prices by sector and source
(2010 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Residential								
Propane	27.61	25.06	23.41	24.77	25.73	26.70	27.99	0.4%
Distillate fuel oil	21.77	26.38	26.91	29.08	31.26	33.71	36.54	1.1%
Natural gas	11.36	10.80	11.78	12.67	13.37	14.60	16.36	1.4%
Electricity	34.52	34.34	33.62	33.96	34.56	35.42	37.10	0.3%
Commercial								
Propane	24.10	22.10	20.04	21.74	22.97	24.23	25.94	0.6%
Distillate fuel oil	21.35	25.87	24.26	26.51	28.51	30.91	33.74	0.9%
Residual fuel oil	11.39	19.17	14.82	16.60	18.77	20.89	23.41	0.7%
Natural gas	9.40	8.84	9.47	10.19	10.70	11.68	13.21	1.4%
Electricity	30.49	29.98	28.57	28.49	28.65	29.66	31.75	0.2%
Industrial[1]								
Propane	23.73	22.54	20.51	22.33	23.64	24.97	26.78	0.6%
Distillate fuel oil	21.87	26.50	24.67	27.02	28.91	31.31	34.16	0.9%
Residual fuel oil	11.30	18.86	17.19	18.96	21.09	23.25	25.78	1.1%
Natural gas[2]	5.48	4.89	5.53	6.15	6.56	7.45	8.88	2.1%
Metallurgical coal	5.96	7.01	8.75	9.36	10.09	10.69	11.11	1.6%
Other industrial coal	2.77	3.43	3.44	3.56	3.71	3.88	4.06	0.6%
Coal to liquids	- -	- -	- -	2.30	2.55	2.76	2.95	- -
Electricity	20.26	19.98	18.72	19.18	19.73	20.80	22.74	0.4%
Transportation								
Propane	27.52	26.06	24.48	25.83	26.80	27.77	29.07	0.4%
E85[3]	25.56	25.30	29.64	27.27	26.94	29.19	30.58	0.7%
Motor gasoline[4]	23.18	28.70	27.84	29.26	30.73	32.99	36.18	0.8%
Jet fuel[5]	16.57	22.49	21.50	23.73	26.03	28.52	31.07	1.1%
Diesel fuel (distillate fuel oil)[6]	22.38	26.15	26.61	28.98	30.81	33.19	36.05	1.1%
Residual fuel oil	10.62	17.83	14.91	16.58	18.34	20.25	22.45	0.8%
Natural gas[7]	16.51	16.14	16.87	17.97	18.90	19.86	21.20	0.9%
Electricity	33.91	32.77	29.60	30.40	31.53	32.84	35.07	0.2%
Electric power[8]								
Distillate fuel oil	19.22	23.30	22.45	24.61	26.80	29.23	32.03	1.1%
Residual fuel oil	12.11	15.97	24.94	27.29	29.36	31.85	34.54	2.7%
Natural gas	5.26	4.77	4.90	5.58	6.05	6.98	8.38	2.0%
Steam coal	2.30	2.38	2.52	2.69	2.87	3.03	3.20	1.0%
Average price to all users[9]								
Propane	16.23	17.13	13.69	16.07	18.14	20.43	23.79	1.1%
E85[3]	25.56	25.30	29.64	27.27	26.94	29.19	30.58	0.7%
Motor gasoline[4]	23.06	28.47	27.84	29.26	30.72	32.99	36.17	0.8%
Jet fuel[5]	16.57	22.49	21.50	23.73	26.03	28.52	31.07	1.1%
Distillate fuel oil	22.17	26.18	26.25	28.62	30.48	32.88	35.73	1.1%
Residual fuel oil	11.06	17.65	15.97	17.72	19.59	21.61	23.95	1.1%
Natural gas	7.27	6.68	7.07	7.76	8.27	9.31	10.94	1.7%
Metallurgical coal	5.96	7.01	8.75	9.36	10.09	10.69	11.11	1.6%
Other coal	2.33	2.45	2.57	2.74	2.92	3.08	3.25	1.0%
Coal to liquids	- -	- -	- -	2.30	2.55	2.76	2.95	- -
Electricity	29.40	29.03	27.50	27.79	28.41	29.55	31.58	0.3%
Non-renewable energy expenditures by sector (billion 2011 dollars)								
Residential	253.56	248.08	243.44	256.13	271.05	290.43	319.63	0.9%
Commercial	182.47	179.97	181.68	192.15	203.80	221.86	249.60	1.1%
Industrial	210.38	225.18	259.03	283.62	294.99	316.87	353.70	1.6%
Transportation	584.31	718.25	694.73	722.24	749.40	808.74	900.68	0.8%
Total non-renewable expenditures	1,230.73	1,371.48	1,378.87	1,454.13	1,519.24	1,637.91	1,823.61	1.0%
Transportation renewable expenditures	0.16	1.24	2.44	3.92	4.39	4.43	5.05	5.0%
Total expenditures	**1,230.88**	**1,372.71**	**1,381.31**	**1,458.06**	**1,523.63**	**1,642.34**	**1,828.66**	**1.0%**

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Residential								
Propane	27.04	25.06	27.00	31.21	35.51	40.35	46.20	2.1%
Distillate fuel oil	21.31	26.38	31.03	36.64	43.14	50.93	60.31	2.9%
Natural gas	11.12	10.80	13.58	15.97	18.45	22.06	27.01	3.2%
Electricity	33.80	34.34	38.76	42.80	47.69	53.52	61.23	2.0%
Commercial								
Propane	23.60	22.10	23.11	27.39	31.70	36.62	42.82	2.3%
Distillate fuel oil	20.91	25.87	27.97	33.41	39.34	46.71	55.68	2.7%
Residual fuel oil	11.15	19.17	17.09	20.92	25.90	31.56	38.64	2.4%
Natural gas	9.20	8.84	10.92	12.85	14.76	17.65	21.81	3.2%
Electricity	29.86	29.98	32.94	35.90	39.54	44.82	52.40	1.9%
Industrial[1]								
Propane	23.23	22.54	23.65	28.14	32.62	37.74	44.20	2.3%
Distillate fuel oil	21.42	26.50	28.45	34.05	39.89	47.31	56.39	2.6%
Residual fuel oil	11.06	18.86	19.82	23.89	29.10	35.13	42.55	2.8%
Natural gas[2]	5.37	4.89	6.38	7.75	9.05	11.25	14.66	3.9%
Metallurgical coal	5.84	7.01	10.09	11.79	13.92	16.15	18.34	3.4%
Other industrial coal	2.71	3.43	3.97	4.48	5.12	5.86	6.70	2.3%
Coal to liquids	- -	- -	- -	2.90	3.52	4.17	4.87	- -
Electricity	19.84	19.98	21.59	24.17	27.22	31.42	37.54	2.2%
Transportation								
Propane	26.95	26.06	28.22	32.56	36.98	41.97	47.97	2.1%
E85[3]	25.03	25.30	34.18	34.37	37.18	44.10	50.46	2.4%
Motor gasoline[4]	22.70	28.70	32.10	36.88	42.41	49.85	59.72	2.6%
Jet fuel[5]	16.22	22.49	24.79	29.90	35.92	43.09	51.27	2.9%
Diesel fuel (distillate fuel oil)[6]	21.91	26.15	30.68	36.52	42.52	50.16	59.50	2.9%
Residual fuel oil	10.40	17.83	17.19	20.89	25.31	30.60	37.06	2.6%
Natural gas[7]	16.17	16.14	19.46	22.65	26.08	30.01	34.98	2.7%
Electricity	33.20	32.77	34.13	38.31	43.51	49.63	57.88	2.0%
Electric power[8]								
Distillate fuel oil	18.82	23.30	25.89	31.02	36.98	44.17	52.87	2.9%
Residual fuel oil	11.86	15.97	28.76	34.39	40.52	48.13	57.01	4.5%
Natural gas	5.15	4.77	5.65	7.03	8.35	10.55	13.83	3.7%
Steam coal	2.25	2.38	2.90	3.39	3.96	4.58	5.28	2.8%

Table A3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Average price to all users[9]								
Propane	15.89	17.13	15.78	20.26	25.03	30.86	39.26	2.9%
E85[3]	25.03	25.30	34.18	34.37	37.18	44.10	50.46	2.4%
Motor gasoline[4]	22.58	28.47	32.10	36.87	42.40	49.84	59.70	2.6%
Jet fuel[5]	16.22	22.49	24.79	29.90	35.92	43.09	51.27	2.9%
Distillate fuel oil	21.71	26.18	30.27	36.06	42.07	49.68	58.97	2.8%
Residual fuel oil	10.83	17.65	18.41	22.33	27.03	32.66	39.53	2.8%
Natural gas	7.12	6.68	8.16	9.78	11.41	14.06	18.06	3.5%
Metallurgical coal	5.84	7.01	10.09	11.79	13.92	16.15	18.34	3.4%
Other coal	2.28	2.45	2.97	3.46	4.03	4.65	5.37	2.7%
Coal to liquids	- -	- -	- -	2.90	3.52	4.17	4.87	- -
Electricity	28.79	29.03	31.71	35.02	39.20	44.65	52.12	2.0%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	248.27	248.08	280.71	322.77	374.04	438.86	527.54	2.6%
Commercial	178.66	179.97	209.48	242.14	281.23	335.25	411.95	2.9%
Industrial	205.99	225.18	298.68	357.41	407.07	478.81	583.76	3.3%
Transportation	572.11	718.25	801.07	910.16	1,034.13	1,222.05	1,486.52	2.5%
Total non-renewable expenditures	1,205.03	1,371.48	1,589.94	1,832.48	2,096.47	2,474.97	3,009.77	2.7%
Transportation renewable expenditures	0.15	1.24	2.81	4.95	6.06	6.70	8.33	6.8%
Total expenditures	**1,205.18**	**1,372.71**	**1,592.75**	**1,837.43**	**2,102.52**	**2,481.67**	**3,018.11**	**2.8%**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2010 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2011 transportation sector natural gas delivered prices are model results. 2010 and 2011 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2010 and 2011 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, Electric Power Monthly, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2010 and 2011 coal prices based on: EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2010 and 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A4. Residential sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Key indicators								
Households (millions)								
Single-family	82.85	83.56	91.25	95.37	99.34	103.03	106.77	0.8%
Multifamily	25.78	26.07	29.82	32.05	34.54	37.05	39.53	1.4%
Mobile homes	6.60	6.54	6.45	6.60	6.75	6.88	7.02	0.2%
Total	**115.23**	**116.17**	**127.52**	**134.02**	**140.63**	**146.96**	**153.32**	**1.0%**
Average house square footage	**1,653**	**1,659**	**1,704**	**1,724**	**1,740**	**1,754**	**1,767**	**0.2%**
Energy intensity								
(million Btu per household)								
Delivered energy consumption	99.2	97.2	86.0	82.5	79.7	77.3	75.5	-0.9%
Total energy consumption	189.0	185.0	161.7	157.4	154.0	151.4	150.6	-0.7%
(thousand Btu per square foot)								
Delivered energy consumption	60.0	58.6	50.4	47.8	45.8	44.1	42.7	-1.1%
Total energy consumption	114.3	111.5	94.9	91.3	88.5	86.3	85.2	-0.9%
Delivered energy consumption by fuel								
Electricity								
Space heating	0.30	0.27	0.29	0.30	0.31	0.32	0.32	0.6%
Space cooling	0.92	0.93	0.95	1.04	1.14	1.23	1.32	1.2%
Water heating	0.45	0.45	0.50	0.52	0.53	0.54	0.55	0.7%
Refrigeration	0.38	0.38	0.38	0.39	0.41	0.43	0.45	0.6%
Cooking	0.11	0.11	0.12	0.13	0.14	0.15	0.16	1.3%
Clothes dryers	0.20	0.20	0.22	0.23	0.24	0.25	0.26	1.0%
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.1%
Lighting	0.65	0.63	0.45	0.40	0.38	0.37	0.38	-1.8%
Clothes washers[1]	0.03	0.03	0.03	0.02	0.02	0.02	0.03	-0.8%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.11	0.12	0.13	0.8%
Televisions and related equipment[2]	0.32	0.32	0.35	0.37	0.40	0.43	0.45	1.2%
Computers and related equipment[3]	0.16	0.16	0.13	0.12	0.12	0.12	0.13	-0.8%
Furnace fans and boiler circulation pumps	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.2%
Other uses[4]	1.11	1.07	1.08	1.21	1.33	1.46	1.62	1.4%
Delivered energy	**4.93**	**4.86**	**4.84**	**5.08**	**5.36**	**5.67**	**6.03**	**0.7%**
Natural gas								
Space heating	3.32	3.25	3.02	2.92	2.85	2.77	2.67	-0.7%
Space cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.1%
Water heating	1.30	1.30	1.33	1.33	1.31	1.27	1.26	-0.1%
Cooking	0.22	0.22	0.22	0.22	0.23	0.23	0.24	0.3%
Clothes dryers	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.7%
Delivered energy	**4.89**	**4.83**	**4.62**	**4.54**	**4.46**	**4.34**	**4.23**	**-0.5%**
Distillate fuel oil								
Space heating	0.49	0.50	0.45	0.40	0.36	0.32	0.29	-1.9%
Water heating	0.10	0.09	0.06	0.05	0.04	0.04	0.03	-3.3%
Delivered energy	**0.58**	**0.59**	**0.51**	**0.45**	**0.40**	**0.36**	**0.32**	**-2.1%**
Propane								
Space heating	0.28	0.27	0.25	0.24	0.23	0.22	0.21	-0.8%
Water heating	0.07	0.07	0.05	0.05	0.05	0.04	0.04	-1.8%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.02	-0.7%
Other uses[5]	0.15	0.16	0.19	0.21	0.22	0.23	0.25	1.5%
Delivered energy	**0.53**	**0.53**	**0.52**	**0.52**	**0.52**	**0.52**	**0.52**	**-0.0%**
Marketed renewables (wood)[6]	0.44	0.45	0.44	0.44	0.45	0.45	0.45	0.1%
Other fuels[7]	0.04	0.02	0.02	0.02	0.02	0.02	0.02	-1.5%

Table A4. Residential sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Delivered energy consumption by end use								
Space heating	4.86	4.76	4.47	4.32	4.22	4.09	3.96	-0.6%
Space cooling	0.92	0.93	0.95	1.04	1.14	1.23	1.32	1.2%
Water heating	1.91	1.91	1.94	1.95	1.93	1.89	1.89	-0.0%
Refrigeration	0.38	0.38	0.38	0.39	0.41	0.43	0.45	0.6%
Cooking	0.36	0.36	0.37	0.38	0.40	0.41	0.42	0.6%
Clothes dryers	0.25	0.25	0.28	0.29	0.30	0.32	0.33	0.9%
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.1%
Lighting	0.65	0.63	0.45	0.40	0.38	0.37	0.38	-1.8%
Clothes washers[1]	0.03	0.03	0.03	0.02	0.02	0.02	0.03	-0.8%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.11	0.12	0.13	0.8%
Televisions and related equipment[2]	0.32	0.32	0.35	0.37	0.40	0.43	0.45	1.2%
Computers and related equipment[3]	0.16	0.16	0.13	0.12	0.12	0.12	0.13	-0.8%
Furnace fans and boiler circulation pumps	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.2%
Other uses[8]	1.26	1.23	1.28	1.41	1.55	1.69	1.87	1.5%
Delivered energy	**11.41**	**11.28**	**10.95**	**11.04**	**11.20**	**11.35**	**11.57**	**0.1%**
Electricity related losses	**10.35**	**10.20**	**9.66**	**10.04**	**10.45**	**10.90**	**11.50**	**0.4%**
Total energy consumption by end use								
Space heating	5.49	5.33	5.05	4.93	4.83	4.71	4.57	-0.5%
Space cooling	2.84	2.88	2.86	3.10	3.35	3.60	3.84	1.0%
Water heating	2.85	2.85	2.95	2.99	2.97	2.92	2.94	0.1%
Refrigeration	1.16	1.16	1.14	1.16	1.21	1.25	1.31	0.4%
Cooking	0.58	0.59	0.62	0.65	0.67	0.70	0.72	0.7%
Clothes dryers	0.66	0.66	0.71	0.74	0.77	0.80	0.83	0.8%
Freezers	0.25	0.26	0.25	0.25	0.25	0.24	0.25	-0.1%
Lighting	2.02	1.97	1.35	1.19	1.11	1.09	1.10	-2.0%
Clothes washers[1]	0.10	0.10	0.08	0.07	0.07	0.07	0.07	-1.0%
Dishwashers[1]	0.32	0.32	0.31	0.31	0.33	0.35	0.37	0.5%
Televisions and related equipment[2]	0.98	0.98	1.05	1.12	1.18	1.25	1.32	1.0%
Computers and related equipment[3]	0.49	0.49	0.39	0.37	0.36	0.36	0.36	-1.0%
Furnace fans and boiler circulation pumps	0.42	0.42	0.42	0.42	0.42	0.42	0.41	-0.0%
Other uses[8]	3.60	3.48	3.44	3.80	4.14	4.49	4.97	1.2%
Total	**21.76**	**21.48**	**20.62**	**21.08**	**21.65**	**22.25**	**23.08**	**0.2%**
Nonmarketed renewables[9]								
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.02	0.03	0.03	4.3%
Solar hot water heating	0.01	0.01	0.02	0.02	0.02	0.02	0.02	1.6%
Solar photovoltaic	0.01	0.02	0.14	0.15	0.17	0.18	0.21	9.1%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	7.0%
Total	**0.03**	**0.04**	**0.20**	**0.21**	**0.22**	**0.24**	**0.27**	**6.9%**
Heating degree days[10]	**4,388**	**4,240**	**4,054**	**3,978**	**3,903**	**3,829**	**3,756**	**-0.4%**
Cooling degree days[10]	**1,498**	**1,528**	**1,499**	**1,545**	**1,591**	**1,638**	**1,685**	**0.3%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, and video game consoles.
[3]Includes desktop and laptop computers, monitors, printers, speakers, networking equipment, and uninterruptible power supplies.
[4]Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Includes such appliances as outdoor grills and mosquito traps.
[6]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2005*.
[7]Includes kerosene and coal.
[8]Includes all other uses listed above.
[9]Consumption determined by using the fossil fuel equivalent of 9,756 Btu per kilowatthour.
[10]See Table A5 for regional detail.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A5. Commercial sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Key indicators								
Total floorspace (billion square feet)								
Surviving	79.3	80.2	87.0	91.9	96.2	100.7	106.4	1.0%
New additions	1.8	1.5	2.1	2.0	2.0	2.3	2.4	1.6%
Total	**81.1**	**81.7**	**89.1**	**93.9**	**98.1**	**103.0**	**108.8**	**1.0%**
Energy consumption intensity (thousand Btu per square foot)								
Delivered energy consumption	105.6	105.2	100.4	98.1	97.2	95.8	93.8	-0.4%
Electricity related losses	117.3	115.7	105.7	104.6	103.7	102.0	100.4	-0.5%
Total energy consumption	222.9	220.9	206.2	202.7	200.9	197.8	194.2	-0.4%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating[1]	0.18	0.17	0.16	0.15	0.15	0.15	0.15	-0.5%
Space cooling[1]	0.56	0.57	0.53	0.54	0.56	0.58	0.59	0.1%
Water heating[1]	0.09	0.09	0.09	0.09	0.09	0.08	0.08	-0.4%
Ventilation	0.49	0.49	0.54	0.56	0.58	0.59	0.60	0.6%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
Lighting	0.96	0.94	0.89	0.90	0.90	0.88	0.87	-0.3%
Refrigeration	0.39	0.38	0.35	0.35	0.36	0.37	0.38	0.0%
Office equipment (PC)	0.21	0.20	0.19	0.20	0.20	0.21	0.22	0.2%
Office equipment (non-PC)	0.23	0.22	0.25	0.27	0.28	0.30	0.31	1.1%
Other uses[2]	1.42	1.41	1.70	1.88	2.08	2.29	2.51	2.0%
Delivered energy	**4.54**	**4.50**	**4.72**	**4.97**	**5.22**	**5.47**	**5.72**	**0.8%**
Natural gas								
Space heating[1]	1.65	1.64	1.66	1.62	1.58	1.53	1.45	-0.4%
Space cooling[1]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-0.3%
Water heating[1]	0.44	0.45	0.50	0.52	0.53	0.54	0.53	0.6%
Cooking	0.18	0.18	0.20	0.21	0.22	0.22	0.23	0.7%
Other uses[3]	0.86	0.91	1.00	1.05	1.13	1.26	1.43	1.6%
Delivered energy	**3.17**	**3.23**	**3.40**	**3.43**	**3.50**	**3.59**	**3.68**	**0.4%**
Distillate fuel oil								
Space heating[1]	0.14	0.13	0.11	0.10	0.09	0.09	0.08	-1.7%
Water heating[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.04	1.0%
Other uses[4]	0.24	0.26	0.20	0.20	0.19	0.19	0.19	-1.1%
Delivered energy	**0.41**	**0.42**	**0.34**	**0.33**	**0.32**	**0.31**	**0.30**	**-1.1%**
Marketed renewables (biomass)	0.11	0.13	0.13	0.13	0.13	0.13	0.13	0.0%
Other fuels[5]	0.34	0.32	0.36	0.37	0.37	0.37	0.38	0.6%
Delivered energy consumption by end use								
Space heating[1]	1.97	1.94	1.93	1.88	1.83	1.76	1.68	-0.5%
Space cooling[1]	0.60	0.61	0.57	0.58	0.59	0.61	0.63	0.1%
Water heating[1]	0.56	0.57	0.62	0.64	0.65	0.66	0.65	0.5%
Ventilation	0.49	0.49	0.54	0.56	0.58	0.59	0.60	0.6%
Cooking	0.20	0.21	0.22	0.23	0.24	0.25	0.25	0.6%
Lighting	0.96	0.94	0.89	0.90	0.90	0.88	0.87	-0.3%
Refrigeration	0.39	0.38	0.35	0.35	0.36	0.37	0.38	0.0%
Office equipment (PC)	0.21	0.20	0.19	0.20	0.20	0.21	0.22	0.2%
Office equipment (non-PC)	0.23	0.22	0.25	0.27	0.28	0.30	0.31	1.1%
Other uses[6]	2.97	3.03	3.38	3.62	3.90	4.23	4.63	1.5%
Delivered energy	**8.57**	**8.60**	**8.95**	**9.22**	**9.54**	**9.86**	**10.21**	**0.6%**

Table A5. Commercial sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Electricity related losses	**9.52**	**9.45**	**9.42**	**9.82**	**10.18**	**10.51**	**10.92**	**0.5%**
Total energy consumption by end use								
Space heating[1]	2.34	2.29	2.24	2.18	2.12	2.05	1.95	-0.5%
Space cooling[1]	1.77	1.81	1.62	1.65	1.68	1.72	1.77	-0.1%
Water heating[1]	0.75	0.76	0.80	0.81	0.82	0.82	0.81	0.2%
Ventilation	1.52	1.53	1.62	1.66	1.70	1.72	1.73	0.4%
Cooking	0.25	0.25	0.27	0.27	0.28	0.29	0.29	0.4%
Lighting	2.97	2.91	2.68	2.68	2.66	2.58	2.52	-0.5%
Refrigeration	1.20	1.18	1.06	1.06	1.07	1.09	1.12	-0.2%
Office equipment (PC)	0.65	0.63	0.57	0.58	0.60	0.61	0.63	-0.0%
Office equipment (non-PC)	0.70	0.70	0.74	0.79	0.84	0.87	0.89	0.9%
Other uses[6]	5.95	5.99	6.77	7.35	7.94	8.63	9.42	1.6%
Total	**18.09**	**18.05**	**18.37**	**19.04**	**19.72**	**20.37**	**21.13**	**0.5%**
Nonmarketed renewable fuels[7]								
Solar thermal	0.08	0.08	0.09	0.10	0.10	0.11	0.12	1.4%
Solar photovoltaic	0.02	0.03	0.10	0.12	0.13	0.16	0.19	6.6%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	7.7%
Total	**0.10**	**0.11**	**0.20**	**0.22**	**0.24**	**0.28**	**0.32**	**3.7%**
Heating Degree Days								
New England	5,944	6,138	6,131	6,062	5,992	5,922	5,850	-0.2%
Middle Atlantic	5,453	5,413	5,362	5,281	5,201	5,121	5,042	-0.2%
East North Central	6,209	6,187	6,073	6,019	5,965	5,911	5,856	-0.2%
West North Central	6,585	6,646	6,297	6,230	6,161	6,091	6,020	-0.3%
South Atlantic	3,183	2,555	2,660	2,627	2,596	2,566	2,538	-0.0%
East South Central	4,003	3,397	3,417	3,400	3,382	3,364	3,345	-0.1%
West South Central	2,503	2,203	2,036	1,996	1,956	1,916	1,876	-0.6%
Mountain	4,882	5,054	4,545	4,430	4,312	4,192	4,071	-0.7%
Pacific	3,202	3,411	3,094	3,076	3,057	3,039	3,022	-0.4%
United States	**4,388**	**4,240**	**4,054**	**3,978**	**3,903**	**3,829**	**3,756**	**-0.4%**
Cooling Degree Days								
New England	655	607	588	611	635	659	683	0.4%
Middle Atlantic	997	887	875	909	944	978	1,011	0.5%
East North Central	978	898	805	815	824	834	844	-0.2%
West North Central	1,123	1,116	995	1,003	1,012	1,021	1,030	-0.3%
South Atlantic	2,289	2,357	2,228	2,271	2,313	2,356	2,397	0.1%
East South Central	1,999	1,811	1,779	1,812	1,845	1,877	1,910	0.2%
West South Central	2,755	3,194	2,847	2,911	2,974	3,037	3,099	-0.1%
Mountain	1,490	1,396	1,698	1,766	1,837	1,910	1,985	1.2%
Pacific	746	809	913	925	938	950	961	0.6%
United States	**1,498**	**1,528**	**1,499**	**1,545**	**1,591**	**1,638**	**1,685**	**0.3%**

[1]Includes fuel consumption for district services.
[2]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, and water services.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[6]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[7]Consumption determined by using the fossil fuel equivalent of 9,756 Btu per kilowatthour.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A6. Industrial sector key indicators and consumption

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Key indicators								
Value of shipments (billion 2005 dollars)								
Manufacturing	4,257	4,438	5,683	6,253	6,712	7,285	7,972	2.0%
Nonmanufacturing	1,585	1,582	2,211	2,295	2,375	2,494	2,644	1.8%
Total	**5,842**	**6,019**	**7,894**	**8,548**	**9,087**	**9,779**	**10,616**	**2.0%**
Energy prices								
(2011 dollars per million Btu)								
Liquefied petroleum gases	23.73	22.54	20.51	22.33	23.64	24.97	26.78	0.6%
Motor gasoline	17.16	17.14	27.71	29.11	30.56	32.80	35.98	2.6%
Distillate fuel oil	21.87	26.50	24.67	27.02	28.91	31.31	34.16	0.9%
Residual fuel oil	11.30	18.86	17.19	18.96	21.09	23.25	25.78	1.1%
Asphalt and road oil	5.74	9.66	11.94	13.28	14.64	16.19	18.05	2.2%
Natural gas heat and power	5.18	4.54	5.19	5.84	6.28	7.18	8.64	2.2%
Natural gas feedstocks	5.81	5.28	5.87	6.47	6.86	7.73	9.15	1.9%
Metallurgical coal	5.96	7.01	8.75	9.36	10.09	10.69	11.11	1.6%
Other industrial coal	2.77	3.43	3.44	3.56	3.71	3.88	4.06	0.6%
Coal to liquids	- -	- -	- -	2.30	2.55	2.76	2.95	- -
Electricity	20.26	19.98	18.72	19.18	19.73	20.80	22.74	0.4%
(nominal dollars per million Btu)								
Liquefied petroleum gases	23.23	22.54	23.65	28.14	32.62	37.74	44.20	2.3%
Motor gasoline	16.80	17.14	31.95	36.69	42.17	49.57	59.39	4.4%
Distillate fuel oil	21.42	26.50	28.45	34.05	39.89	47.31	56.39	2.6%
Residual fuel oil	11.06	18.86	19.82	23.89	29.10	35.13	42.55	2.8%
Asphalt and road oil	5.62	9.66	13.77	16.73	20.20	24.46	29.78	4.0%
Natural gas heat and power	5.07	4.54	5.99	7.36	8.66	10.85	14.25	4.0%
Natural gas feedstocks	5.69	5.28	6.77	8.15	9.46	11.68	15.10	3.7%
Metallurgical coal	5.84	7.01	10.09	11.79	13.92	16.15	18.34	3.4%
Other industrial coal	2.71	3.43	3.97	4.48	5.12	5.86	6.70	2.3%
Coal to liquids	- -	- -	- -	2.90	3.52	4.17	4.87	- -
Electricity	19.84	19.98	21.59	24.17	27.22	31.42	37.54	2.2%
Energy consumption (quadrillion Btu)[1]								
Industrial consumption excluding refining								
Liquefied petroleum gases heat and power	0.09	0.07	0.06	0.06	0.06	0.06	0.07	-0.2%
Liquefied petroleum gases feedstocks	2.02	2.02	2.40	2.48	2.41	2.34	2.24	0.4%
Propylene	0.41	0.40	0.56	0.56	0.52	0.49	0.46	0.6%
Motor gasoline	0.28	0.27	0.32	0.32	0.32	0.32	0.32	0.6%
Distillate fuel oil	1.19	1.20	1.22	1.19	1.18	1.19	1.22	0.0%
Residual fuel oil	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Petrochemical feedstocks	0.94	0.88	1.03	1.08	1.08	1.08	1.09	0.7%
Petroleum coke	0.16	0.15	0.33	0.35	0.34	0.34	0.34	3.0%
Asphalt and road oil	0.88	0.86	1.11	1.13	1.16	1.21	1.30	1.4%
Miscellaneous petroleum[2]	0.71	0.67	0.43	0.41	0.37	0.36	0.37	-2.0%
Petroleum subtotal	6.80	6.62	7.57	7.69	7.55	7.50	7.52	0.4%
Natural gas heat and power	4.81	5.03	5.74	5.84	5.84	5.93	6.04	0.6%
Natural gas feedstocks	0.48	0.46	0.55	0.55	0.51	0.48	0.45	-0.1%
Lease and plant fuel[3]	1.31	1.42	1.57	1.68	1.73	1.84	1.97	1.1%
Natural gas subtotal	6.60	6.91	7.86	8.07	8.09	8.25	8.45	0.7%
Metallurgical coal and coke[4]	0.55	0.57	0.59	0.55	0.48	0.42	0.41	-1.1%
Other industrial coal	1.00	1.04	1.00	1.00	1.00	1.02	1.05	0.0%
Coal subtotal	1.54	1.62	1.58	1.56	1.48	1.44	1.46	-0.3%
Renewables[5]	1.47	1.51	1.72	1.85	1.97	2.11	2.28	1.4%
Purchased electricity	3.10	3.12	3.74	3.84	3.75	3.68	3.68	0.6%
Delivered energy	**19.52**	**19.78**	**22.47**	**23.00**	**22.83**	**22.97**	**23.39**	**0.6%**
Electricity related losses	6.51	6.55	7.46	7.59	7.30	7.07	7.02	0.2%
Total	**26.03**	**26.33**	**29.93**	**30.59**	**30.14**	**30.05**	**30.41**	**0.5%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Refining consumption								
Liquefied petroleum gases heat and power	0.01	0.00	0.00	0.00	0.00	0.00	0.00	- -
Distillate fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual fuel oil	0.01	0.00	0.00	0.00	0.00	0.00	0.00	- -
Petroleum coke	0.52	0.53	0.42	0.40	0.40	0.40	0.41	-0.9%
Still gas	1.41	1.40	1.25	1.19	1.19	1.21	1.23	-0.4%
Miscellaneous petroleum[2]	0.01	0.01	0.00	0.00	0.00	0.00	0.00	-22.9%
Petroleum subtotal	1.96	1.95	1.67	1.59	1.59	1.61	1.64	-0.6%
Natural gas heat and power	1.38	1.43	1.57	1.60	1.62	1.61	1.60	0.4%
Natural-gas-to-liquids heat and power	0.00	0.00	0.13	0.16	0.21	0.27	0.33	- -
Natural gas subtotal	1.38	1.43	1.70	1.77	1.83	1.88	1.93	1.0%
Other industrial coal	0.06	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal-to-liquids heat and power	0.00	0.00	0.00	0.07	0.09	0.12	0.15	- -
Coal subtotal	0.06	0.00	0.00	0.07	0.09	0.12	0.15	- -
Biofuels heat and coproducts	0.85	0.67	0.82	0.82	0.85	0.97	1.37	2.5%
Purchased electricity	0.21	0.21	0.21	0.21	0.21	0.22	0.23	0.3%
Delivered energy	**4.46**	**4.26**	**4.40**	**4.46**	**4.57**	**4.80**	**5.31**	**0.8%**
Electricity related losses	0.44	0.44	0.42	0.41	0.41	0.41	0.43	-0.0%
Total	**4.90**	**4.70**	**4.82**	**4.87**	**4.98**	**5.21**	**5.75**	**0.7%**
Total industrial sector consumption								
Liquefied petroleum gases heat and power	0.10	0.08	0.06	0.06	0.06	0.06	0.07	-0.5%
Liquefied petroleum gases feedstocks	2.02	2.02	2.40	2.48	2.41	2.34	2.24	0.4%
Propylene	0.41	0.40	0.56	0.56	0.52	0.49	0.46	0.6%
Motor gasoline	0.28	0.27	0.32	0.32	0.32	0.32	0.32	0.6%
Distillate fuel oil	1.19	1.21	1.22	1.19	1.18	1.19	1.22	0.0%
Residual fuel oil	0.12	0.11	0.11	0.11	0.11	0.11	0.11	-0.1%
Petrochemical feedstocks	0.94	0.88	1.03	1.08	1.08	1.08	1.09	0.7%
Petroleum coke	0.68	0.67	0.75	0.75	0.73	0.74	0.75	0.4%
Asphalt and road oil	0.88	0.86	1.11	1.13	1.16	1.21	1.30	1.4%
Still gas	1.41	1.40	1.25	1.19	1.19	1.21	1.23	-0.4%
Miscellaneous petroleum[2]	0.73	0.68	0.43	0.41	0.37	0.36	0.37	-2.1%
Petroleum subtotal	8.76	8.57	9.25	9.28	9.14	9.11	9.16	0.2%
Natural gas heat and power	6.19	6.46	7.31	7.44	7.46	7.54	7.63	0.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.13	0.16	0.21	0.27	0.33	- -
Natural gas feedstocks	0.48	0.46	0.55	0.55	0.51	0.48	0.45	-0.1%
Lease and plant fuel[3]	1.31	1.42	1.57	1.68	1.73	1.84	1.97	1.1%
Natural gas subtotal	7.98	8.34	9.56	9.84	9.91	10.13	10.38	0.8%
Metallurgical coal and coke[4]	0.55	0.57	0.59	0.55	0.48	0.42	0.41	-1.1%
Other industrial coal	1.06	1.04	1.00	1.00	1.00	1.02	1.05	0.0%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.07	0.09	0.12	0.15	- -
Coal subtotal	1.60	1.62	1.58	1.63	1.57	1.56	1.61	-0.0%
Biofuels heat and coproducts	0.85	0.67	0.82	0.82	0.85	0.97	1.37	2.5%
Renewables[5]	1.47	1.51	1.72	1.85	1.97	2.11	2.28	1.4%
Purchased electricity	3.31	3.33	3.95	4.05	3.96	3.90	3.91	0.6%
Delivered energy	**23.98**	**24.04**	**26.87**	**27.46**	**27.40**	**27.77**	**28.71**	**0.6%**
Electricity related losses	6.95	6.99	7.89	8.00	7.72	7.49	7.45	0.2%
Total	**30.93**	**31.03**	**34.76**	**35.46**	**35.11**	**35.26**	**36.16**	**0.5%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Energy consumption per dollar of shipments (thousand Btu per 2005 dollar)								
Liquid fuels and other petroleum	1.50	1.42	1.17	1.09	1.01	0.93	0.86	-1.7%
Natural gas	1.37	1.39	1.23	1.17	1.11	1.06	1.01	-1.1%
Coal	0.27	0.27	0.20	0.19	0.17	0.16	0.15	-1.9%
Renewable fuels[5]	0.40	0.36	0.32	0.31	0.31	0.32	0.34	-0.2%
Purchased electricity	0.57	0.55	0.50	0.47	0.44	0.40	0.37	-1.4%
Delivered energy	**4.11**	**3.99**	**3.42**	**3.23**	**3.04**	**2.87**	**2.74**	**-1.3%**
Industrial combined heat and power[1]								
Capacity (gigawatts)	25.07	25.63	29.47	32.44	36.48	41.55	45.07	2.0%
Generation (billion kilowatthours)	123.76	122.05	164.19	182.40	206.62	237.92	260.03	2.6%

[1]Includes energy for combined heat and power plants that have a regulatory status, and small on-site generating systems.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[4]Includes net coal coke imports.
[5]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.

Sources: 2010 and 2011 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 and 2011 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2010 and 2011 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2010 and 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 natural gas prices: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 natural gas prices: *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2010 refining consumption values are based on: *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2011 refining consumption based on: *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). Other 2010 and 2011 consumption values are based on: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 shipments: IHS Global Insight, Global Insight Industry model, August 2012. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A7. Transportation sector key indicators and delivered energy consumption

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Key indicators								
Travel indicators								
(billion vehicle miles traveled)								
Light-duty vehicles less than 8,501 pounds	2,654	2,629	2,870	3,089	3,323	3,532	3,719	1.2%
Commercial light trucks[1]	65	65	80	87	94	102	110	1.8%
Freight trucks greater than 10,000 pounds	235	240	323	350	371	401	438	2.1%
(billion seat miles available)								
Air	999	982	1,082	1,131	1,177	1,222	1,274	0.9%
(billion ton miles traveled)								
Rail	1,581	1,557	1,719	1,833	1,910	1,969	2,017	0.9%
Domestic shipping	508	514	612	600	578	584	591	0.5%
Energy efficiency indicators								
(miles per gallon)								
New light-duty vehicle CAFE standard[2]	25.5	27.6	37.0	46.8	47.2	47.5	47.8	1.9%
New car[2]	27.7	30.9	43.9	54.6	54.6	54.7	54.7	2.0%
New light truck[2]	23.4	24.6	30.9	39.5	39.5	39.5	39.5	1.6%
Compliance new light-duty vehicle[3]	31.8	32.6	37.9	47.3	48.2	48.6	49.0	1.4%
New car[3]	36.1	37.4	44.4	55.0	55.6	55.9	56.1	1.4%
New light truck[3]	28.1	28.5	32.0	40.0	40.3	40.4	40.5	1.2%
Tested new light-duty vehicle[4]	30.8	31.5	37.9	47.3	48.1	48.6	49.0	1.5%
New car[4]	35.7	36.4	44.4	55.0	55.6	55.8	56.1	1.5%
New light truck[4]	26.9	27.3	32.0	40.0	40.3	40.4	40.4	1.4%
On-road new light-duty vehicle[5]	24.9	25.5	30.6	38.2	38.9	39.3	39.7	1.5%
New car[5]	29.1	29.8	36.3	44.9	45.4	45.6	45.8	1.5%
New light truck[5]	21.5	21.8	25.6	32.0	32.3	32.3	32.3	1.4%
Light-duty stock[6]	20.9	20.6	24.1	27.6	31.3	34.2	36.1	2.0%
New commercial light truck[1]	18.2	18.1	20.0	23.9	24.1	24.2	24.2	1.0%
Stock commercial light truck[1]	14.6	14.9	17.9	20.1	22.2	23.5	24.1	1.7%
Freight truck	6.7	6.7	7.3	7.7	8.0	8.1	8.2	0.7%
(seat miles per gallon)								
Aircraft	62.3	62.3	63.9	65.2	67.0	69.2	71.5	0.5%
(ton miles per thousand Btu)								
Rail	3.4	3.4	3.5	3.5	3.5	3.5	3.5	0.1%
Domestic shipping	2.4	2.4	2.5	2.5	2.5	2.5	2.6	0.2%
Energy use by mode (quadrillion Btu)								
Light-duty vehicles	15.94	15.56	14.35	13.48	12.77	12.44	12.43	-0.8%
Commercial light trucks[1]	0.55	0.54	0.56	0.54	0.53	0.54	0.57	0.2%
Bus transportation	0.25	0.25	0.27	0.28	0.29	0.31	0.32	0.9%
Freight trucks	4.86	4.95	6.07	6.24	6.39	6.76	7.31	1.4%
Rail, passenger	0.05	0.05	0.05	0.06	0.06	0.06	0.06	1.1%
Rail, freight	0.46	0.45	0.49	0.53	0.54	0.56	0.57	0.8%
Shipping, domestic	0.21	0.21	0.25	0.24	0.23	0.23	0.23	0.3%
Shipping, international	0.85	0.80	0.81	0.82	0.82	0.83	0.84	0.2%
Recreational boats	0.25	0.24	0.26	0.27	0.28	0.28	0.29	0.6%
Air	2.52	2.46	2.65	2.73	2.78	2.82	2.86	0.5%
Military use	0.76	0.74	0.63	0.65	0.68	0.72	0.77	0.1%
Lubricants	0.14	0.13	0.12	0.12	0.12	0.13	0.13	-0.1%
Pipeline fuel	0.68	0.70	0.71	0.73	0.74	0.76	0.78	0.4%
Total	**27.52**	**27.09**	**27.24**	**26.68**	**26.24**	**26.43**	**27.14**	**0.0%**

Table A7. Transportation sector key indicators and delivered energy consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Energy use by mode (million barrels per day oil equivalent)								
Light-duty vehicles	8.37	8.46	7.85	7.38	6.99	6.80	6.80	-0.7%
Commercial light trucks[1]	0.28	0.28	0.29	0.28	0.27	0.28	0.29	0.2%
Bus transportation	0.12	0.12	0.13	0.14	0.14	0.15	0.15	0.9%
Freight trucks	2.34	2.39	2.92	3.01	3.08	3.25	3.52	1.3%
Rail, passenger	0.02	0.02	0.02	0.03	0.03	0.03	0.03	1.1%
Rail, freight	0.22	0.22	0.24	0.25	0.26	0.27	0.27	0.8%
Shipping, domestic	0.10	0.10	0.12	0.11	0.11	0.11	0.11	0.3%
Shipping, international	0.37	0.35	0.35	0.36	0.36	0.36	0.37	0.2%
Recreational boats	0.13	0.13	0.14	0.15	0.15	0.15	0.16	0.6%
Air	1.22	1.19	1.28	1.32	1.35	1.36	1.38	0.5%
Military use	0.37	0.36	0.30	0.31	0.33	0.35	0.37	0.1%
Lubricants	0.07	0.06	0.06	0.06	0.06	0.06	0.06	-0.1%
Pipeline fuel	0.32	0.33	0.34	0.34	0.35	0.36	0.37	0.4%
Total	**13.93**	**14.00**	**14.05**	**13.73**	**13.47**	**13.53**	**13.87**	**-0.0%**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales and credit banking.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]Combined"on-the-road" estimate for all cars and light trucks.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.

Sources: 2010 and 2011: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012); Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II - User and Fuel Data), April 2011; EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010/2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1,797	1,688	1,613	1,680	1,718	1,756	1,776	0.2%
Petroleum	32	24	15	15	15	15	16	-1.5%
Natural gas[3]	779	809	948	996	1,093	1,193	1,224	1.4%
Nuclear power	807	790	885	912	908	875	903	0.5%
Pumped storage/other[4]	2	1	2	2	3	3	3	2.2%
Renewable sources[5]	392	484	555	582	598	644	750	1.5%
Distributed generation (natural gas)	0	0	3	6	10	12	13	- -
Total	**3,809**	**3,797**	**4,021**	**4,194**	**4,345**	**4,497**	**4,684**	**0.7%**
Combined heat and power[6]								
Coal	31	27	27	27	27	28	28	0.2%
Petroleum	2	2	1	1	1	1	1	-4.1%
Natural gas	123	121	130	131	128	127	125	0.1%
Renewable sources	5	4	4	4	4	4	4	-0.2%
Total	**163**	**157**	**161**	**162**	**161**	**160**	**158**	**0.0%**
Total electric power sector generation	**3,972**	**3,954**	**4,182**	**4,356**	**4,506**	**4,658**	**4,842**	**0.7%**
Less direct use	17	12	13	13	13	13	13	0.0%
Net available to the grid	**3,956**	**3,942**	**4,169**	**4,343**	**4,493**	**4,645**	**4,830**	**0.7%**
End-use sector[7]								
Coal	20	15	16	20	21	23	25	1.7%
Petroleum	2	2	2	2	2	2	2	0.2%
Natural gas	69	70	104	120	148	187	221	4.0%
Other gaseous fuels[8]	10	11	14	14	14	14	14	0.9%
Renewable sources[9]	32	36	68	75	82	92	104	3.7%
Other[10]	4	4	4	4	4	4	4	-0.3%
Total end-use sector generation	**138**	**139**	**208**	**235**	**271**	**322**	**370**	**3.4%**
Less direct use	99	102	169	192	225	269	310	3.9%
Total sales to the grid	**39**	**37**	**39**	**43**	**47**	**53**	**60**	**1.7%**
Total electricity generation by fuel								
Coal	1847	1730	1656	1727	1766	1807	1829	0.2%
Petroleum	37	28	17	18	18	18	18	-1.5%
Natural gas	970	1000	1184	1252	1379	1519	1582	1.6%
Nuclear power	807	790	885	912	908	875	903	0.5%
Renewable sources[5,9]	429	524	627	661	685	740	858	1.7%
Other[11]	19	20	20	20	20	21	21	0.1%
Total electricity generation	**4110**	**4093**	**4389**	**4591**	**4777**	**4979**	**5212**	**0.8%**
Net generation to the grid	**3994**	**3979**	**4208**	**4386**	**4540**	**4698**	**4890**	**0.7%**
Net imports	**26**	**37**	**24**	**22**	**14**	**10**	**18**	**-2.4%**
Electricity sales by sector								
Residential	1446	1424	1419	1488	1572	1661	1767	0.7%
Commercial	1330	1319	1384	1455	1531	1602	1677	0.8%
Industrial	971	976	1158	1186	1161	1142	1145	0.6%
Transportation	6	6	9	11	13	16	19	3.9%
Total	**3753**	**3725**	**3969**	**4140**	**4276**	**4421**	**4608**	**0.7%**
Direct use	116	114	181	204	237	281	322	3.6%
Total electricity use	**3,870**	**3,841**	**4,151**	**4,344**	**4,513**	**4,702**	**4,930**	**0.9%**

Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
End-use prices								
(2011 cents per kilowatthour)								
Residential	11.8	11.7	11.5	11.6	11.8	12.1	12.7	0.3%
Commercial	10.4	10.2	9.7	9.7	9.8	10.1	10.8	0.2%
Industrial	6.9	6.8	6.4	6.5	6.7	7.1	7.8	0.4%
Transportation	11.6	11.2	10.1	10.4	10.8	11.2	12.0	0.2%
All sectors average	**10.0**	**9.9**	**9.4**	**9.5**	**9.7**	**10.1**	**10.8**	**0.3%**
(nominal cents per kilowatthour)								
Residential	11.5	11.7	13.2	14.6	16.3	18.3	20.9	2.0%
Commercial	10.2	10.2	11.2	12.2	13.5	15.3	17.9	1.9%
Industrial	6.8	6.8	7.4	8.2	9.3	10.7	12.8	2.2%
Transportation	11.3	11.2	11.6	13.1	14.8	16.9	19.7	2.0%
All sectors average	**9.8**	**9.9**	**10.8**	**12.0**	**13.4**	**15.2**	**17.8**	**2.0%**
Prices by service category								
(2011 cents per kilowatthour)								
Generation	6.0	5.8	5.6	5.8	6.0	6.4	7.1	0.7%
Transmission	1.0	1.1	1.1	1.1	1.1	1.1	1.1	0.3%
Distribution	3.0	3.1	2.8	2.6	2.6	2.6	2.6	-0.5%
(nominal cents per kilowatthour)								
Generation	5.9	5.8	6.4	7.3	8.3	9.6	11.6	2.5%
Transmission	1.0	1.1	1.2	1.4	1.5	1.7	1.9	2.0%
Distribution	2.9	3.1	3.2	3.3	3.6	4.0	4.3	1.2%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	5.00	4.42	1.35	1.43	1.50	1.60	1.66	-3.3%
Nitrogen oxide (million short tons)	2.07	1.94	1.72	1.80	1.82	1.85	1.87	-0.1%
Mercury (short tons)	33.14	31.49	6.84	7.19	7.33	7.55	7.75	-4.7%

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes plants that only produce electricity and have a regulatory status.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2011 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or have a regulatory status).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), and supporting databases. 2010 and 2011 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2010 and 2011 electricity prices by service category: EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. **Projections**: EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A9. Electricity generating capacity
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Electric power sector[2]								
Power only[3]								
Coal	308.0	309.5	268.7	267.9	267.9	267.9	269.0	-0.5%
Oil and natural gas steam[4]	105.6	101.9	86.4	78.3	69.1	66.6	64.0	-1.6%
Combined cycle	171.8	179.5	193.2	207.6	238.3	265.8	288.4	1.6%
Combustion turbine/diesel	134.5	136.1	149.9	162.1	177.2	190.2	208.9	1.5%
Nuclear power[5]	101.2	101.1	110.6	114.1	113.6	109.3	113.1	0.4%
Pumped storage	22.3	22.3	22.3	22.3	22.3	22.3	22.3	0.0%
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8%
Renewable sources[6]	125.3	132.3	152.9	155.6	159.7	174.3	206.8	1.6%
Distributed generation[7]	0.0	0.0	0.9	1.9	3.1	4.1	5.1	- -
Total	**968.7**	**982.8**	**985.0**	**1,009.8**	**1,051.2**	**1,100.7**	**1,177.7**	**0.6%**
Combined heat and power[8]								
Coal	4.9	4.9	4.3	4.2	4.2	4.2	4.2	-0.5%
Oil and natural gas steam[4]	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.0%
Combined cycle	26.0	26.0	26.0	26.0	26.0	26.0	26.0	0.0%
Combustion turbine/diesel	2.8	2.8	2.8	2.8	2.8	2.8	2.8	-0.1%
Renewable sources[6]	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.2%
Total	**35.3**	**35.3**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**-0.1%**
Cumulative planned additions[9]								
Coal	0.0	0.0	6.1	6.1	6.1	6.1	6.1	- -
Oil and natural gas steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	0.0	0.0	10.9	10.9	10.9	10.9	10.9	- -
Combustion turbine/diesel	0.0	0.0	5.6	5.6	5.6	5.6	5.6	- -
Nuclear power	0.0	0.0	5.5	5.5	5.5	5.5	5.5	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	18.1	18.1	18.1	18.1	18.1	- -
Distributed generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**46.3**	**46.3**	**46.3**	**46.3**	**46.3**	**- -**
Cumulative unplanned additions[9]								
Coal	0.0	0.0	0.3	0.3	0.3	0.4	1.5	- -
Oil and natural gas steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	0.0	0.0	3.1	17.4	48.2	75.7	98.3	- -
Combustion turbine/diesel	0.0	0.0	15.4	28.0	43.3	56.4	75.3	- -
Nuclear power	0.0	0.0	0.0	0.0	0.0	0.8	5.5	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	3.7	6.4	10.5	25.2	57.6	- -
Distributed generation[7]	0.0	0.0	0.9	1.9	3.1	4.1	5.1	- -
Total	**0.0**	**0.0**	**23.4**	**54.1**	**105.4**	**162.4**	**243.3**	**- -**
Cumulative electric power sector additions	**0.0**	**0.0**	**69.7**	**100.4**	**151.7**	**208.7**	**289.5**	**- -**
Cumulative retirements[10]								
Coal	0.0	0.0	47.9	48.8	48.8	48.8	48.8	- -
Oil and natural gas steam[4]	0.0	0.0	15.5	23.6	32.8	35.3	37.9	- -
Combined cycle	0.0	0.0	0.2	0.2	0.2	0.2	0.2	- -
Combustion turbine/diesel	0.0	0.0	7.3	7.7	7.9	7.9	8.2	- -
Nuclear power	0.0	0.0	0.6	0.6	1.1	6.1	7.1	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	1.2	1.2	1.2	1.2	1.2	- -
Total	**0.0**	**0.0**	**72.7**	**82.1**	**92.0**	**99.6**	**103.4**	**- -**
Total electric power sector capacity	**1,004.1**	**1,018.1**	**1,019.6**	**1,044.4**	**1,085.8**	**1,135.3**	**1,212.3**	**0.6%**

Table A9. Electricity generating capacity (continued)
(gigawatts)

Net summer capacity[1]	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
End-use generators[11]								
Coal	3.6	3.6	3.6	4.2	4.4	4.6	4.9	1.1%
Petroleum	0.7	0.7	1.0	1.0	1.0	1.0	1.0	1.0%
Natural gas	15.1	15.0	17.2	19.7	24.1	30.1	35.1	3.0%
Other gaseous fuels[12]	1.6	2.0	2.1	2.1	2.1	2.1	2.1	0.1%
Renewable sources[6]	7.2	8.9	24.2	26.3	29.1	32.7	37.5	5.1%
Other[13]	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.8%
Total	**28.7**	**30.6**	**48.5**	**53.7**	**61.1**	**71.0**	**81.0**	**3.4%**
Cumulative capacity additions[9]	**0.0**	**0.0**	**17.9**	**23.1**	**30.5**	**40.3**	**50.4**	**- -**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 8.0 gigawatts of uprates through 2040.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[9]Cumulative additions after December 31, 2011.
[10]Cumulative retirements after December 31, 2011.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes refinery gas and still gas.
[13]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A10. Electricity trade
(billion kilowatthours, unless otherwise noted)

Electricity trade	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Interregional electricity trade								
Gross domestic sales								
Firm power	237.5	173.8	104.4	47.1	24.2	24.2	24.2	-6.6%
Economy	150.1	158.1	162.7	167.5	189.9	186.3	220.2	1.1%
Total	**387.6**	**332.0**	**267.1**	**214.6**	**214.1**	**210.5**	**244.4**	**-1.1%**
Gross domestic sales (million 2011 dollars)								
Firm power	14,548.9	10,648.8	6,393.5	2,884.8	1,481.3	1,481.3	1,481.3	-6.6%
Economy	7,192.7	6,457.3	8,615.5	9,945.5	10,174.8	11,041.2	15,088.4	3.0%
Total	**21,741.6**	**17,106.2**	**15,008.9**	**12,830.3**	**11,656.1**	**12,522.5**	**16,569.7**	**-0.1%**
International electricity trade								
Imports from Canada and Mexico								
Firm power	13.7	15.0	17.1	5.2	0.4	0.4	0.4	-11.9%
Economy	31.4	37.4	25.6	34.8	31.3	27.5	35.5	-0.2%
Total	**45.1**	**52.4**	**42.7**	**40.0**	**31.7**	**27.8**	**35.8**	**-1.3%**
Exports to Canada and Mexico								
Firm power	3.7	2.6	1.3	0.4	0.0	0.0	0.0	- -
Economy	15.7	12.8	17.3	18.0	18.0	17.8	17.8	1.1%
Total	**19.4**	**15.4**	**18.6**	**18.4**	**18.0**	**17.8**	**17.8**	**0.5%**

- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports. Firm power sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.
Sources: 2010 and 2011 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2007; NERC, 2011 Summer Reliability Assessment (May 2011); and NERC, Winter Reliability Assessment 2011/2012 (November 2011). 2010 and 2011 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2010*, DOE/EIA-0348(2010) (Washington, DC, November 2011). 2010 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2010*. 2011 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2011*. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A11. Liquid fuels supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Crude oil								
Domestic crude production[1]	5.47	5.67	7.47	6.79	6.30	6.26	6.13	0.3%
Alaska	0.60	0.57	0.49	0.35	0.38	0.35	0.41	-1.1%
Lower 48 states	4.88	5.10	6.98	6.44	5.92	5.91	5.72	0.4%
Net imports	9.17	8.89	6.82	7.05	7.36	7.37	7.57	-0.6%
Gross imports	9.21	8.94	6.82	7.05	7.36	7.37	7.57	-0.6%
Exports	0.04	0.05	0.00	0.00	0.00	0.00	0.00	- -
Other crude supply[2]	0.07	0.26	0.00	0.00	0.00	0.00	0.00	- -
Total crude supply	**14.72**	**14.81**	**14.29**	**13.84**	**13.66**	**13.63**	**13.70**	**-0.3%**
Other petroleum supply	**3.41**	**3.02**	**4.04**	**4.12**	**3.82**	**3.57**	**3.29**	**0.3%**
Natural gas plant liquids	2.07	2.22	3.13	3.17	2.90	2.91	2.92	1.0%
Net product imports	0.29	-0.30	-0.13	-0.04	-0.08	-0.37	-0.67	2.7%
Gross refined product imports[3]	1.23	1.15	1.47	1.50	1.53	1.50	1.42	0.7%
Unfinished oil imports	0.61	0.69	0.56	0.53	0.51	0.48	0.45	-1.5%
Blending component imports	0.74	0.72	0.63	0.59	0.54	0.48	0.40	-2.0%
Exports	2.29	2.86	2.79	2.66	2.67	2.84	2.94	0.1%
Refinery processing gain[4]	1.07	1.08	1.04	0.99	1.00	1.02	1.03	-0.1%
Product stock withdrawal	-0.03	0.03	0.00	0.00	0.00	0.00	0.00	- -
Other non-petroleum supply	**1.03**	**1.09**	**1.51**	**1.55**	**1.58**	**1.68**	**1.97**	**2.1%**
Supply from renewable sources	0.86	0.90	1.18	1.15	1.14	1.19	1.43	1.6%
Ethanol	0.84	0.84	1.08	1.04	0.99	0.96	0.97	0.5%
Domestic production	0.87	0.91	1.01	0.98	0.95	0.91	0.89	-0.1%
Net imports	-0.02	-0.07	0.07	0.06	0.04	0.05	0.08	- -
Biodiesel	0.02	0.06	0.08	0.08	0.08	0.08	0.08	1.0%
Domestic production	0.02	0.06	0.07	0.07	0.07	0.07	0.07	0.4%
Net imports	-0.01	-0.00	0.01	0.01	0.01	0.01	0.01	- -
Other biomass-derived liquids[5]	0.00	0.00	0.02	0.03	0.06	0.14	0.38	21.6%
Liquids from gas	0.00	0.00	0.08	0.10	0.13	0.16	0.20	- -
Liquids from coal	0.00	0.00	0.00	0.03	0.04	0.05	0.06	- -
Other[6]	0.17	0.18	0.25	0.26	0.28	0.28	0.28	1.5%
Total primary supply[7]	**19.16**	**18.92**	**19.84**	**19.50**	**19.06**	**18.88**	**18.96**	**0.0%**
Liquid fuels consumption								
by fuel								
Liquefied petroleum gases	2.27	2.30	2.90	2.97	2.90	2.83	2.75	0.6%
E85[8]	0.00	0.03	0.06	0.10	0.11	0.10	0.11	4.3%
Motor gasoline[9]	8.99	8.74	8.34	7.78	7.34	7.14	7.12	-0.7%
Jet fuel[10]	1.43	1.42	1.52	1.56	1.60	1.63	1.66	0.5%
Distillate fuel oil[11]	3.80	3.90	4.48	4.55	4.56	4.59	4.67	0.6%
Diesel	3.32	3.51	4.04	4.14	4.18	4.23	4.33	0.7%
Residual fuel oil	0.54	0.46	0.50	0.50	0.50	0.51	0.51	0.4%
Other[12]	2.14	2.08	2.04	2.04	2.03	2.06	2.11	0.1%
by sector								
Residential and commercial	1.06	1.06	1.01	0.97	0.95	0.93	0.91	-0.5%
Industrial[13]	4.48	4.43	5.10	5.15	5.05	5.01	5.00	0.4%
Transportation	13.57	13.63	13.65	13.29	12.95	12.84	12.95	-0.2%
Electric power[14]	0.17	0.13	0.08	0.08	0.08	0.08	0.08	-1.5%
Total	**19.17**	**18.95**	**19.84**	**19.50**	**19.04**	**18.86**	**18.95**	**0.0%**
Discrepancy[15]	**-0.01**	**-0.03**	**0.01**	**0.01**	**0.02**	**0.02**	**0.01**	**- -**

Table A11. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Domestic refinery distillation capacity[16]	17.6	17.7	17.5	17.5	17.5	17.5	17.5	-0.0%
Capacity utilization rate (percent)[17]	86.0	86.0	90.7	87.8	86.7	86.5	86.9	0.0%
Net import share of product supplied (percent)	49.3	45.0	34.1	36.3	38.5	37.4	36.9	-0.7%
Net expenditures for imported crude oil and petroleum products (billion 2011 dollars)	248.26	362.66	259.66	296.86	342.67	378.36	433.65	0.6%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]End-of-year operable capacity.
[17]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). Other 2010 data: EIA, *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). Other 2011 data: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A12. Petroleum product prices
(2010 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Crude oil prices (2011 dollars per barrel)								
Brent spot	81.31	111.26	105.57	117.36	130.47	145.41	162.68	1.3%
West Texas Intermediate spot	81.08	94.86	103.57	115.36	128.47	143.41	160.68	1.8%
Average imported refiners acquisition cost[1]	77.49	102.65	102.19	113.48	125.64	138.70	154.96	1.4%
Delivered sector product prices								
Residential								
Propane	2.34	2.13	1.98	2.09	2.17	2.25	2.35	0.3%
Distillate fuel oil	3.02	3.66	3.73	4.03	4.34	4.67	5.07	1.1%
Commercial								
Distillate fuel oil	2.94	3.57	3.34	3.65	3.93	4.26	4.65	0.9%
Residual fuel oil	1.70	2.87	2.22	2.49	2.81	3.13	3.50	0.7%
Residual fuel oil (2011 dollars per barrel)	71.59	120.49	93.20	104.39	117.99	131.32	147.19	0.7%
Industrial[2]								
Propane	2.01	1.92	1.74	1.88	1.99	2.10	2.25	0.5%
Distillate fuel oil	3.01	3.64	3.39	3.71	3.97	4.30	4.69	0.9%
Residual fuel oil	1.69	2.82	2.57	2.84	3.16	3.48	3.86	1.1%
Residual fuel oil (2011 dollars per barrel)	71.03	118.58	108.07	119.19	132.58	146.16	162.10	1.1%
Transportation								
Propane	2.33	2.22	2.07	2.18	2.26	2.34	2.44	0.3%
Ethanol (E85)[3]	2.44	2.42	2.83	2.60	2.57	2.79	2.92	0.7%
Ethanol wholesale price	1.75	2.54	3.00	2.66	2.28	2.32	2.48	-0.1%
Motor gasoline[4]	2.88	3.45	3.32	3.49	3.67	3.94	4.32	0.8%
Jet fuel[5]	2.24	3.04	2.90	3.20	3.51	3.85	4.19	1.1%
Diesel fuel (distillate fuel oil)[6]	3.07	3.58	3.65	3.97	4.22	4.55	4.94	1.1%
Residual fuel oil	1.59	2.67	2.23	2.48	2.75	3.03	3.36	0.8%
Residual fuel oil (2011 dollars per barrel)	66.79	112.11	93.74	104.23	115.30	127.30	141.16	0.8%
Electric power[7]								
Distillate fuel oil	2.67	3.23	3.11	3.41	3.72	4.05	4.44	1.1%
Residual fuel oil	1.81	2.39	3.73	4.09	4.39	4.77	5.17	2.7%
Residual fuel oil (2011 dollars per barrel)	76.16	100.43	156.82	171.59	184.59	200.24	217.18	2.7%
Refined petroleum product prices[8]								
Propane	1.37	1.46	1.16	1.36	1.53	1.72	2.00	1.1%
Motor gasoline[4]	2.86	3.42	3.32	3.49	3.67	3.94	4.32	0.8%
Jet fuel[5]	2.24	3.04	2.90	3.20	3.51	3.85	4.19	1.1%
Distillate fuel oil	3.04	3.59	3.60	3.93	4.18	4.51	4.90	1.1%
Residual fuel oil	1.66	2.64	2.39	2.65	2.93	3.24	3.59	1.1%
Residual fuel oil (2011 dollars per barrel)	69.52	110.98	100.39	111.40	123.16	135.88	150.58	1.1%
Average	**2.59**	**3.11**	**3.01**	**3.22**	**3.43**	**3.72**	**4.10**	**1.0%**

Table A12. Petroleum product prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Crude oil spot prices (nominal dollars per barrel)								
Brent spot	79.61	111.26	121.73	147.90	180.04	219.73	268.50	3.1%
West Texas Intermediate spot	79.39	94.86	119.43	145.38	177.28	216.70	265.20	3.6%
Average imported refiners acquisition cost[1]	75.87	102.65	117.84	143.00	173.38	209.59	255.76	3.2%
Delivered sector product prices								
Residential								
Propane	2.29	2.13	2.29	2.63	2.99	3.40	3.88	2.1%
Distillate fuel oil	2.96	3.66	4.30	5.08	5.98	7.06	8.37	2.9%
Commercial								
Distillate fuel oil	2.88	3.57	3.86	4.61	5.42	6.44	7.68	2.7%
Residual fuel oil	1.67	2.87	2.56	3.13	3.88	4.72	5.78	2.4%
Residual fuel oil (nominal dollars per barrel)	70.09	120.49	107.46	131.55	162.83	198.44	242.92	2.4%
Industrial[2]								
Propane	1.97	1.92	2.00	2.38	2.75	3.18	3.71	2.3%
Distillate fuel oil	2.95	3.64	3.91	4.67	5.48	6.49	7.74	2.6%
Residual fuel oil	1.66	2.82	2.97	3.58	4.36	5.26	6.37	2.8%
Residual fuel oil (nominal dollars per barrel)	69.54	118.58	124.61	150.20	182.96	220.86	267.54	2.8%
Transportation								
Propane	2.28	2.22	2.39	2.75	3.12	3.53	4.03	2.1%
Ethanol (E85)[3]	2.39	2.42	3.26	3.28	3.55	4.21	4.82	2.4%
Ethanol wholesale price	1.71	2.54	3.46	3.36	3.14	3.51	4.09	1.7%
Motor gasoline[4]	2.82	3.45	3.83	4.40	5.06	5.95	7.13	2.5%
Jet fuel[5]	2.19	3.04	3.35	4.04	4.85	5.82	6.92	2.9%
Diesel fuel (distillate fuel oil)[6]	3.00	3.58	4.20	5.00	5.83	6.87	8.15	2.9%
Residual fuel oil	1.56	2.67	2.57	3.13	3.79	4.58	5.55	2.6%
Residual fuel oil (nominal dollars per barrel)	65.40	112.11	108.09	131.35	159.10	192.35	232.98	2.6%
Electric power[7]								
Distillate fuel oil	2.61	3.23	3.59	4.30	5.13	6.13	7.33	2.9%
Residual fuel oil	1.78	2.39	4.31	5.15	6.06	7.20	8.53	4.5%
Residual fuel oil (nominal dollars per barrel)	74.57	100.43	180.83	216.23	254.72	302.58	358.45	4.5%
Refined petroleum product prices[8]								
Propane	1.35	1.46	1.34	1.71	2.11	2.60	3.30	2.9%
Motor gasoline[4]	2.81	3.42	3.83	4.40	5.06	5.95	7.13	2.6%
Jet fuel[5]	2.19	3.04	3.35	4.04	4.85	5.82	6.92	2.9%
Distillate fuel oil	2.98	3.59	4.15	4.95	5.77	6.81	8.09	2.8%
Residual fuel oil	1.62	2.64	2.76	3.34	4.05	4.89	5.92	2.8%
Residual fuel oil (nominal dollars per barrel)	68.06	110.98	115.76	140.38	169.95	205.33	248.53	2.8%
Average	**2.54**	**3.11**	**3.47**	**4.06**	**4.74**	**5.62**	**6.76**	**2.7%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 and 2011 crude oil spot prices: Thomson Reuters. 2010 and 2011 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2010 and 2011 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2010 and 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2010 and 2011 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Supply								
Dry gas production[1]	21.33	23.00	26.61	28.59	29.79	31.35	33.14	1.3%
Supplemental natural gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.2%
Net imports	2.60	1.95	-0.14	-1.58	-2.10	-2.55	-3.55	- -
Pipeline[3]	2.24	1.67	0.13	-0.52	-0.67	-1.09	-2.09	- -
Liquefied natural gas	0.37	0.28	-0.26	-1.06	-1.43	-1.46	-1.46	- -
Total supply	**24.00**	**25.01**	**26.54**	**27.07**	**27.75**	**28.86**	**29.65**	**0.6%**
Consumption by sector								
Residential	4.78	4.72	4.52	4.44	4.36	4.24	4.14	-0.5%
Commercial	3.10	3.16	3.32	3.35	3.42	3.51	3.60	0.4%
Industrial[4]	6.52	6.77	7.68	7.82	7.79	7.84	7.90	0.5%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.13	0.16	0.21	0.26	0.33	- -
Natural gas to liquids production[6]	0.00	0.00	0.14	0.17	0.22	0.28	0.35	- -
Electric power[7]	7.39	7.60	8.23	8.45	8.89	9.44	9.50	0.8%
Transportation[8]	0.04	0.04	0.08	0.12	0.26	0.59	1.04	11.9%
Pipeline fuel	0.67	0.68	0.70	0.71	0.73	0.74	0.76	0.4%
Lease and plant fuel[9]	1.28	1.39	1.54	1.64	1.70	1.81	1.93	1.1%
Total consumption	**23.78**	**24.37**	**26.32**	**26.87**	**27.57**	**28.71**	**29.54**	**0.7%**
Discrepancy[10]	**0.22**	**0.64**	**0.22**	**0.20**	**0.18**	**0.15**	**0.12**	**- -**
Natural gas spot price at Henry Hub								
(2011 dollars per million Btu)	4.46	3.98	4.13	4.87	5.40	6.32	7.83	2.4%
(nominal dollars per million Btu)	4.37	3.98	4.77	6.14	7.45	9.55	12.92	4.1%
Delivered natural gas prices								
(2011 dollars per thousand cubic feet)								
Residential	11.62	11.05	12.05	12.97	13.68	14.93	16.74	1.4%
Commercial	9.61	9.04	9.69	10.43	10.94	11.95	13.52	1.4%
Industrial[4]	5.61	5.00	5.66	6.29	6.71	7.62	9.09	2.1%
Electric power[7]	5.37	4.87	5.00	5.70	6.18	7.13	8.55	2.0%
Transportation[11]	16.89	16.51	17.26	18.39	19.34	20.31	21.68	0.9%
Average[12]	**7.44**	**6.83**	**7.23**	**7.93**	**8.45**	**9.51**	**11.18**	**1.7%**
(nominal dollars per thousand cubic feet)								
Residential	11.38	11.05	13.89	16.34	18.87	22.57	27.63	3.2%
Commercial	9.41	9.04	11.17	13.14	15.10	18.06	22.31	3.2%
Industrial[4]	5.49	5.00	6.52	7.93	9.26	11.51	14.99	3.9%
Electric power[7]	5.26	4.87	5.76	7.18	8.53	10.77	14.12	3.7%
Transportation[11]	16.54	16.51	19.90	23.17	26.68	30.70	35.79	2.7%
Average[12]	**7.28**	**6.83**	**8.34**	**9.99**	**11.66**	**14.37**	**18.46**	**3.5%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[8]Natural gas used as vehicle fuel.
[9]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2010 and 2011 values include net storage injections.
[11]Natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[12]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2010 and 2011 consumption based on: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 natural gas price at Henry Hub based on daily spot prices published in Natural Gas Intelligence. 2010 and 2011 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2010 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011) and estimated state taxes, federal taxes, and dispensing costs or charges. 2011 transportation sector delivered prices are model results. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A14. Oil and gas supply

Production and supply	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Crude oil								
Lower 48 average wellhead price[1] (2011 dollars per barrel)	**76.78**	**96.55**	**103.49**	**115.61**	**129.26**	**143.31**	**160.38**	**1.8%**
Production (million barrels per day)[2]								
United States total	5.47	5.67	7.47	6.79	6.30	6.26	6.13	0.3%
Lower 48 onshore	3.21	3.67	5.29	4.99	4.48	4.19	3.97	0.3%
Tight oil[3]	0.82	1.22	2.81	2.63	2.19	2.06	2.02	1.7%
Carbon dioxide enhanced oil recovery	0.28	0.24	0.29	0.43	0.56	0.65	0.66	3.5%
Other	2.11	2.20	2.19	1.93	1.72	1.48	1.30	-1.8%
Lower 48 offshore	1.67	1.43	1.69	1.46	1.44	1.72	1.75	0.7%
Alaska	0.60	0.57	0.49	0.35	0.38	0.35	0.41	-1.1%
Lower 48 end of year reserves[2] (billion barrels)	**21.46**	**21.36**	**24.63**	**24.37**	**24.92**	**26.19**	**26.72**	**0.8%**
Natural gas								
Natural gas spot price at Henry Hub (2011 dollars per million Btu)	4.46	3.98	4.13	4.87	5.40	6.32	7.83	2.4%
Dry production (trillion cubic feet)[4]								
United States total	21.33	23.00	26.61	28.59	29.79	31.35	33.14	1.3%
Lower 48 onshore	18.54	20.54	24.27	25.67	26.26	27.35	29.12	1.2%
Associated-dissolved[5]	1.47	1.54	2.14	1.99	1.43	1.26	1.09	-1.2%
Non-associated	17.07	19.00	22.13	23.67	24.83	26.10	28.03	1.4%
Tight gas	6.34	5.86	6.40	6.56	6.67	6.96	7.34	0.8%
Shale gas	4.86	7.85	11.05	12.84	14.17	15.33	16.70	2.6%
Coalbed methane	1.69	1.71	1.71	1.66	1.69	1.73	2.11	0.7%
Other	4.18	3.58	2.97	2.61	2.31	2.07	1.87	-2.2%
Lower 48 offshore	2.44	2.11	2.07	2.19	2.34	2.81	2.85	1.0%
Associated-dissolved[5]	0.59	0.54	0.66	0.64	0.60	0.74	0.74	1.1%
Non-associated	1.85	1.58	1.41	1.55	1.73	2.07	2.11	1.0%
Alaska	0.35	0.35	0.28	0.73	1.19	1.18	1.18	4.3%
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**295.79**	**298.96**	**332.51**	**342.08**	**350.65**	**356.26**	**359.97**	**0.6%**
Supplemental gas supplies (trillion cubic feet)[6]	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.2%**
Total lower 48 wells drilled (thousands)	**43.27**	**41.10**	**48.84**	**54.26**	**57.91**	**63.76**	**76.65**	**2.2%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[6]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 and 2011 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2010 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2010) (Washington, DC, August 2012). 2010 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2010 and 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2011 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2010 and 2011 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A15. Coal supply, disposition, and prices
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Production[1]								
Appalachia	336	337	288	295	295	289	283	-0.6%
Interior	156	171	198	203	212	217	226	1.0%
West	592	588	585	616	646	664	658	0.4%
East of the Mississippi	446	456	438	447	456	455	453	-0.0%
West of the Mississippi	638	639	633	666	697	716	714	0.4%
Total	**1,084**	**1,096**	**1,071**	**1,113**	**1,153**	**1,171**	**1,167**	**0.2%**
Waste coal supplied[2]	**14**	**13**	**19**	**21**	**20**	**23**	**27**	**2.7%**
Net imports								
Imports[3]	18	11	2	5	5	22	36	4.0%
Exports	82	107	127	129	144	158	159	1.4%
Total	**-64**	**-96**	**-125**	**-124**	**-139**	**-136**	**-123**	**0.9%**
Total supply[4]	**1,034**	**1,012**	**966**	**1,010**	**1,034**	**1,058**	**1,071**	**0.2%**
Consumption by sector								
Residential and commercial	3	3	3	3	3	3	3	-0.3%
Coke plants	21	21	23	22	20	18	18	-0.7%
Other industrial[5]	49	46	50	50	50	51	52	0.4%
Coal-to-liquids heat and power	0	0	0	3	5	6	8	- -
Coal to liquids production	0	0	0	3	4	5	6	- -
Electric power[6]	975	929	890	929	953	975	984	0.2%
Total	**1,049**	**999**	**966**	**1,010**	**1,034**	**1,058**	**1,071**	**0.2%**
Discrepancy and stock change[7]	**-14**	**13**	**0**	**-0**	**0**	**1**	**0**	**- -**
Average minemouth price[8]								
(2011 dollars per short ton)	36.37	41.16	49.26	52.02	55.64	58.57	61.28	1.4%
(2011 dollars per million Btu)	1.80	2.04	2.45	2.60	2.79	2.94	3.08	1.4%
Delivered prices[9]								
(2011 dollars per short ton)								
Coke plants	156.87	184.44	229.19	245.15	264.13	279.68	290.84	1.6%
Other industrial[5]	65.76	70.68	72.44	74.98	78.25	81.84	85.63	0.7%
Coal to liquids	- -	- -	- -	49.54	47.71	53.07	55.60	- -
Electric power[6]								
(2011 dollars per short ton)	45.21	46.38	47.91	51.14	54.37	57.39	60.77	0.9%
(2011 dollars per million Btu)	2.30	2.38	2.52	2.69	2.87	3.03	3.20	1.0%
Average	**48.40**	**50.64**	**53.47**	**56.58**	**59.53**	**62.37**	**65.70**	**0.9%**
Exports[10]	122.98	148.86	168.73	172.99	177.76	177.60	176.05	0.6%

Table A15. Coal supply, disposition, and prices (continued)
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Average minemouth price[8]								
(nominal dollars per short ton)	35.61	41.16	56.81	65.55	76.78	88.51	101.14	3.1%
(nominal dollars per million Btu)	1.76	2.04	2.83	3.27	3.85	4.44	5.08	3.2%
Delivered prices[9]								
(nominal dollars per short ton)								
Coke plants	153.59	184.44	264.27	308.93	364.48	422.61	480.01	3.4%
Other industrial[5]	64.38	70.68	83.52	94.49	107.97	123.66	141.33	2.4%
Coal to liquids	- -	- -	- -	62.44	65.84	80.19	91.77	- -
Electric power[6]								
(nominal dollars per short ton)	44.27	46.38	55.24	64.45	75.02	86.73	100.29	2.7%
(nominal dollars per million Btu)	2.25	2.38	2.90	3.39	3.96	4.58	5.28	2.8%
Average	**47.39**	**50.64**	**61.66**	**71.30**	**82.14**	**94.24**	**108.43**	**2.7%**
Exports[10]	120.41	148.86	194.56	217.99	245.30	268.37	290.56	2.3%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[9]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[10]F.a.s. price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012); EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012); and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A16. Renewable energy generating capacity and generation
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Electric power sector[1]								
Net summer capacity								
Conventional hydropower	77.82	77.87	78.34	78.94	79.11	79.63	80.31	0.1%
Geothermal[2]	2.38	2.38	3.63	4.34	5.70	6.60	7.46	4.0%
Municipal waste[3]	3.26	3.34	3.44	3.44	3.44	3.44	3.44	0.1%
Wood and other biomass[4]	2.38	2.37	2.82	2.83	2.85	3.16	3.70	1.6%
Solar thermal	0.49	0.49	1.35	1.35	1.35	1.35	1.35	3.6%
Solar photovoltaic[5]	0.37	1.01	5.37	5.91	6.80	11.84	24.54	11.6%
Wind	39.40	45.68	58.81	59.62	61.30	69.14	86.83	2.2%
Offshore wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Total electric power sector capacity	**126.09**	**133.14**	**153.75**	**156.43**	**160.54**	**175.17**	**207.63**	**1.5%**
Generation (billion kilowatthours)								
Conventional hydropower	258.46	323.14	288.54	291.38	292.39	295.18	297.28	-0.3%
Geothermal[2]	15.22	16.70	25.28	30.98	42.02	49.36	56.40	4.3%
Biogenic municipal waste[6]	15.78	16.62	14.09	14.09	14.09	14.09	14.10	-0.6%
Wood and other biomass	11.45	10.50	54.45	68.99	65.48	66.41	75.64	7.0%
Dedicated plants	10.37	9.35	14.85	15.12	15.30	17.62	21.59	2.9%
Cofiring	1.07	1.16	39.60	53.87	50.18	48.79	54.05	14.2%
Solar thermal	0.79	0.81	2.74	2.74	2.73	2.73	2.73	4.3%
Solar photovoltaic[5]	0.42	0.97	9.83	10.99	13.40	24.81	56.22	15.0%
Wind	94.62	119.63	163.48	166.73	172.11	195.46	251.94	2.6%
Offshore wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Total electric power sector generation	**396.73**	**488.38**	**558.41**	**585.90**	**602.22**	**648.05**	**754.32**	**1.5%**
End-use sectors[7]								
Net summer capacity								
Conventional hydropower	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal waste[8]	0.35	0.46	0.46	0.46	0.46	0.46	0.46	0.0%
Biomass	4.57	4.92	6.87	7.62	8.34	9.16	10.18	2.5%
Solar photovoltaic[5]	1.82	3.02	15.63	16.95	18.94	21.53	25.08	7.6%
Wind	0.17	0.21	0.87	0.92	1.05	1.23	1.51	7.1%
Total end-use sector capacity	**7.24**	**8.93**	**24.15**	**26.28**	**29.12**	**32.71**	**37.55**	**5.1%**
Generation (billion kilowatthours)								
Conventional hydropower	1.75	1.89	1.82	1.82	1.82	1.82	1.82	-0.1%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal waste[8]	1.94	2.04	3.55	3.55	3.55	3.55	3.55	1.9%
Biomass	25.73	26.75	36.95	41.35	45.55	50.32	56.25	2.6%
Solar photovoltaic[5]	2.85	4.71	24.53	26.69	29.91	34.10	39.97	7.7%
Wind	0.22	0.28	1.23	1.31	1.50	1.76	2.15	7.4%
Total end-use sector generation	**32.48**	**35.68**	**68.09**	**74.72**	**82.33**	**91.56**	**103.74**	**3.7%**

Table A16. Renewable energy generating capacity and generation (continued)
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Total, all sectors								
Net summer capacity								
Conventional hydropower	78.15	78.20	78.66	79.27	79.43	79.96	80.64	0.1%
Geothermal	2.38	2.38	3.63	4.34	5.70	6.60	7.46	4.0%
Municipal waste	3.61	3.80	3.89	3.89	3.89	3.89	3.89	0.1%
Wood and other biomass[4]	6.95	7.29	9.69	10.45	11.19	12.32	13.88	2.2%
Solar[5]	2.67	4.52	22.35	24.22	27.09	34.73	50.96	8.7%
Wind	39.57	45.88	59.68	60.54	62.35	70.37	88.35	2.3%
Total capacity, all sectors	**133.33**	**142.06**	**177.90**	**182.71**	**189.66**	**207.88**	**245.17**	**1.9%**
Generation (billion kilowatthours)								
Conventional hydropower	260.20	325.03	290.37	293.20	294.21	297.01	299.11	-0.3%
Geothermal	15.22	16.70	25.28	30.98	42.02	49.36	56.40	4.3%
Municipal waste	17.71	18.66	17.63	17.64	17.64	17.64	17.64	-0.2%
Wood and other biomass	37.17	37.26	91.40	110.34	111.03	116.73	131.89	4.5%
Solar[5]	4.05	6.50	37.10	40.42	46.04	61.65	98.92	9.8%
Wind	94.85	119.91	164.71	168.04	173.61	197.22	254.10	2.6%
Total generation, all sectors	**429.21**	**524.06**	**626.49**	**660.62**	**684.55**	**739.61**	**858.06**	**1.7%**

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2010, EIA estimates that as much as 245 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2010, plus an additional 558 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, , DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[6]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2011 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2010 and 2011 generation: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

Sector and source	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Marketed renewable energy[1]								
Residential (wood)	**0.44**	**0.45**	**0.44**	**0.44**	**0.45**	**0.45**	**0.45**	**0.1%**
Commercial (biomass)	**0.11**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.0%**
Industrial[2]	**2.32**	**2.18**	**2.53**	**2.67**	**2.82**	**3.08**	**3.65**	**1.8%**
Conventional hydroelectric	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.0%
Municipal waste[3]	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.1%
Biomass	1.27	1.31	1.51	1.65	1.77	1.91	2.08	1.6%
Biofuels heat and coproducts	0.85	0.67	0.82	0.82	0.85	0.97	1.37	2.5%
Transportation	**1.14**	**1.22**	**1.60**	**1.58**	**1.58**	**1.71**	**2.21**	**2.1%**
Ethanol used in E85[4]	0.00	0.03	0.05	0.09	0.11	0.10	0.11	4.3%
Ethanol used in gasoline blending	1.09	1.06	1.35	1.26	1.19	1.15	1.15	0.3%
Biodiesel used in distillate blending	0.03	0.12	0.16	0.16	0.16	0.16	0.16	1.0%
Liquids from biomass	0.00	0.00	0.02	0.04	0.10	0.27	0.76	- -
Renewable diesel and gasoline[5]	0.01	0.00	0.02	0.02	0.02	0.02	0.02	7.9%
Electric power[6]	**3.85**	**4.74**	**5.49**	**5.77**	**5.93**	**6.38**	**7.44**	**1.6%**
Conventional hydroelectric	2.52	3.15	2.82	2.84	2.85	2.88	2.90	-0.3%
Geothermal	0.15	0.16	0.25	0.30	0.41	0.48	0.55	4.3%
Biogenic municipal waste[7]	0.05	0.05	0.07	0.07	0.07	0.07	0.07	0.8%
Biomass	0.20	0.19	0.64	0.79	0.76	0.78	0.88	5.4%
Dedicated plants	0.17	0.15	0.24	0.24	0.24	0.28	0.33	2.7%
Cofiring	0.02	0.04	0.40	0.55	0.51	0.50	0.55	9.9%
Solar thermal	0.01	0.01	0.03	0.03	0.03	0.03	0.03	4.3%
Solar photovoltaic	0.00	0.01	0.10	0.11	0.13	0.24	0.55	15.0%
Wind	0.92	1.17	1.59	1.63	1.68	1.91	2.46	2.6%
Total marketed renewable energy	**7.85**	**8.71**	**10.19**	**10.58**	**10.89**	**11.75**	**13.87**	**1.6%**
Sources of ethanol								
from corn and other starch	1.13	1.18	1.29	1.25	1.22	1.17	1.13	-0.1%
from cellulose	0.00	0.00	0.02	0.02	0.02	0.02	0.02	13.8%
Net imports	-0.03	-0.09	0.09	0.08	0.06	0.06	0.11	- -
Total	**1.09**	**1.09**	**1.40**	**1.35**	**1.29**	**1.25**	**1.26**	**0.5%**

Table A17. Renewable energy consumption by sector and source (continued)
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Nonmarketed renewable energy[8]								
Selected consumption								
Residential	**0.03**	**0.04**	**0.20**	**0.21**	**0.22**	**0.24**	**0.27**	**6.9%**
Solar hot water heating	0.01	0.01	0.02	0.02	0.02	0.02	0.02	1.6%
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.02	0.03	0.03	4.3%
Solar photovoltaic	0.01	0.02	0.14	0.15	0.17	0.18	0.21	9.1%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	7.0%
Commercial	**0.10**	**0.11**	**0.20**	**0.22**	**0.24**	**0.28**	**0.32**	**3.7%**
Solar thermal	0.08	0.08	0.09	0.10	0.10	0.11	0.12	1.4%
Solar photovoltaic	0.02	0.03	0.10	0.12	0.13	0.16	0.19	6.6%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	7.7%

[1]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2.
[2]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Excludes motor gasoline component of E85.
[5]Renewable feedstocks for the on-site production of diesel and gasoline.
[6]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status. Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, geothermal, solar, and wind. Consumption at hydroelectric, geothermal, solar, and wind facilities determined by using the fossil fuel equivalent of 9,756 Btu per kilowatthour.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2011 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The U.S. Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 ethanol: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2010 and 2011 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Residential								
Petroleum	85	78	71	66	62	59	57	-1.1%
Natural gas	267	256	245	241	236	230	225	-0.5%
Coal	1	1	1	1	1	0	0	-0.8%
Electricity[1]	875	828	744	776	817	862	888	0.2%
Total residential	**1,228**	**1,162**	**1,061**	**1,084**	**1,117**	**1,152**	**1,170**	**0.0%**
Commercial								
Petroleum	51	49	47	46	45	45	44	-0.3%
Natural gas	173	171	180	182	186	191	195	0.5%
Coal	6	5	5	5	5	5	5	0.0%
Electricity[1]	805	767	725	760	796	831	843	0.3%
Total commercial	**1,034**	**992**	**957**	**992**	**1,032**	**1,071**	**1,087**	**0.3%**
Industrial[2]								
Petroleum	344	345	355	349	342	342	347	0.0%
Natural gas[3]	408	417	491	506	511	523	538	0.9%
Coal	157	143	154	157	152	150	155	0.3%
Electricity[1]	587	567	607	619	604	592	575	0.0%
Total industrial	**1,496**	**1,472**	**1,606**	**1,631**	**1,608**	**1,607**	**1,615**	**0.3%**
Transportation								
Petroleum[4]	1,836	1,802	1,785	1,744	1,705	1,695	1,712	-0.2%
Natural gas[5]	36	39	42	45	53	72	97	3.2%
Electricity[1]	4	4	5	6	7	8	10	3.3%
Total transportation	**1,876**	**1,845**	**1,831**	**1,794**	**1,766**	**1,776**	**1,819**	**-0.0%**
Electric power[6]								
Petroleum	33	25	13	14	14	14	14	-2.0%
Natural gas	399	411	446	458	482	511	514	0.8%
Coal	1,828	1,718	1,610	1,678	1,717	1,757	1,775	0.1%
Other[7]	12	11	11	11	11	11	11	0.0%
Total electric power	**2,271**	**2,166**	**2,081**	**2,161**	**2,224**	**2,293**	**2,315**	**0.2%**
Total by fuel								
Petroleum[4]	2,349	2,299	2,270	2,218	2,169	2,156	2,175	-0.2%
Natural gas	1,283	1,294	1,404	1,431	1,468	1,528	1,569	0.7%
Coal	1,990	1,867	1,769	1,841	1,874	1,912	1,936	0.1%
Other[7]	12	11	11	11	11	11	11	0.0%
Total	**5,634**	**5,471**	**5,455**	**5,501**	**5,523**	**5,607**	**5,691**	**0.1%**
Carbon dioxide emissions (tons per person)	**18.2**	**17.5**	**16.0**	**15.4**	**14.8**	**14.4**	**14.1**	**-0.8%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2009, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as vehicle fuel.
[6]Includes electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 emissions and emission factors: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/10) (Washington, DC, October 2011). 2011 emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and end use	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Residential								
Space heating	285.69	274.74	255.95	247.75	241.43	234.50	224.88	-0.7%
Space cooling	162.29	158.49	146.49	159.05	173.02	187.28	194.44	0.7%
Water heating	159.50	156.30	155.23	157.27	156.47	154.26	153.31	-0.1%
Refrigeration	66.67	63.92	58.33	59.80	62.44	65.23	66.18	0.1%
Cooking	32.50	31.97	32.51	33.82	35.31	36.76	37.50	0.6%
Clothes dryers	37.70	36.32	36.43	38.02	39.80	41.64	42.10	0.5%
Freezers	14.58	14.07	12.72	12.69	12.67	12.72	12.53	-0.4%
Lighting	115.65	108.10	69.37	61.08	57.56	56.74	55.83	-2.3%
Clothes washers[1]	5.81	5.54	4.19	3.82	3.62	3.70	3.76	-1.3%
Dishwashers[1]	18.27	17.62	15.99	16.02	16.94	18.21	18.93	0.2%
Televisions and related equipment[2]	56.31	54.02	53.97	57.27	60.97	64.92	66.79	0.7%
Computers and related equipment[3]	28.12	26.74	20.20	18.98	18.84	18.91	18.42	-1.3%
Furnace fans and boiler circulation pumps	23.83	22.95	21.43	21.52	21.61	21.64	20.96	-0.3%
Other uses	206.69	192.29	178.57	197.45	216.66	235.95	254.42	1.0%
Discrepancy[4]	13.90	-0.72	-0.66	-0.60	-0.55	-0.49	-0.45	-1.6%
Total residential	**1,227.53**	**1,162.33**	**1,060.73**	**1,083.95**	**1,116.78**	**1,151.98**	**1,169.60**	**0.0%**
Commercial								
Space heating[5]	129.14	125.16	120.43	116.90	113.92	110.05	104.21	-0.6%
Space cooling[5]	100.98	99.43	83.32	85.01	86.89	89.61	89.71	-0.4%
Water heating[5]	41.26	41.42	42.51	43.21	43.77	43.83	42.91	0.1%
Ventilation	86.72	84.34	82.87	85.39	87.72	89.24	87.81	0.1%
Cooking	13.53	13.60	14.12	14.39	14.79	15.11	15.10	0.4%
Lighting	170.14	159.77	137.50	137.62	137.71	134.23	127.51	-0.8%
Refrigeration	68.65	64.87	54.38	54.23	55.14	56.54	56.50	-0.5%
Office equipment (PC)	37.41	34.69	29.46	29.97	31.21	31.99	31.91	-0.3%
Office equipment (non-PC)	40.15	38.30	37.97	40.72	43.33	45.18	45.13	0.6%
Other uses[6]	346.27	330.16	354.48	384.84	417.63	455.24	486.52	1.3%
Total commercial	**1,034.26**	**991.74**	**957.03**	**992.28**	**1,032.11**	**1,071.02**	**1,087.30**	**0.3%**
Industrial[7]								
Manufacturing								
Refining	261.87	256.26	245.90	249.79	254.75	261.90	270.14	0.2%
Food products	99.97	99.13	103.10	107.71	110.82	113.57	115.35	0.5%
Paper products	77.52	71.94	69.45	70.41	70.83	71.37	72.28	0.0%
Bulk chemicals	259.35	246.50	257.53	256.29	241.10	227.51	214.99	-0.5%
Glass	19.21	18.88	22.35	24.03	24.70	24.88	25.48	1.0%
Cement manufacturing	26.02	26.85	39.05	39.26	39.72	41.88	44.97	1.8%
Iron and steel	118.17	123.07	147.83	143.48	125.21	111.79	106.29	-0.5%
Aluminum	44.84	46.19	56.02	57.93	50.38	43.21	34.05	-1.0%
Fabricated metal products	37.67	39.72	39.70	39.25	37.79	37.42	37.35	-0.2%
Machinery	23.70	25.44	28.77	29.63	29.82	30.32	31.47	0.7%
Computers and electronics	31.55	29.96	32.14	33.80	34.77	36.31	37.13	0.7%
Transportation equipment	47.09	50.85	61.43	65.04	68.29	72.17	73.71	1.3%
Electrical equipment	8.02	7.98	8.86	9.07	9.17	9.73	10.47	0.9%
Wood products	17.11	16.80	21.91	22.06	21.26	20.68	19.87	0.6%
Plastics	39.27	40.00	38.28	38.25	38.44	37.97	36.39	-0.3%
Balance of manufacturing	141.86	139.34	146.13	155.71	162.73	171.45	180.33	0.9%
Total manufacturing	1,253.22	1,238.92	1,318.46	1,341.71	1,319.77	1,312.15	1,310.27	0.2%
Nonmanufacturing								
Agriculture	72.17	68.36	68.84	68.02	67.75	67.61	67.44	-0.0%
Construction	69.98	66.71	92.16	92.34	93.37	95.63	99.14	1.4%
Mining	55.72	55.52	57.67	55.57	53.64	53.07	51.75	-0.2%
Total nonmanufacturing	197.87	190.59	218.67	215.93	214.76	216.31	218.33	0.5%
Discrepancy[4]	45.06	42.57	68.69	73.07	73.73	78.98	86.73	2.5%
Total industrial	**1,496.14**	**1,472.08**	**1,605.81**	**1,630.71**	**1,608.26**	**1,607.44**	**1,615.33**	**0.3%**

Table A19. Energy-related carbon dioxide emissions by end use (continued)
(million metric tons)

Sector and end use	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Transportation								
Light-duty vehicles	1,059.53	1,036.67	929.21	870.47	824.70	804.78	804.29	-0.9%
Commercial light trucks[8]	38.08	37.35	37.93	36.83	35.97	36.60	38.70	0.1%
Bus transportation	17.81	17.20	17.55	17.79	17.96	18.08	18.27	0.2%
Freight trucks	350.67	352.73	430.98	442.74	450.92	471.42	502.86	1.2%
Rail, passenger	5.63	5.54	5.74	6.04	6.33	6.66	6.81	0.7%
Rail, freight	33.43	32.40	35.40	37.59	38.96	39.97	40.76	0.8%
Shipping, domestic	15.77	15.75	18.43	17.91	17.12	17.12	17.18	0.3%
Shipping, international	66.38	62.27	63.27	63.88	64.50	65.06	65.55	0.2%
Recreational boats	16.94	16.30	17.08	17.69	18.28	18.78	19.13	0.6%
Air	178.28	174.72	187.90	193.68	197.37	199.69	202.49	0.5%
Military use	54.58	52.66	45.19	46.04	48.49	51.34	54.59	0.1%
Lubricants	5.24	4.95	4.50	4.56	4.62	4.69	4.78	-0.1%
Pipeline fuel	36.30	37.11	37.76	38.73	39.33	40.34	41.19	0.4%
Discrepancy[4]	-2.97	-1.06	0.04	0.54	1.10	1.69	2.26	- -
Total transportation	**1,875.67**	**1,844.58**	**1,830.99**	**1,794.48**	**1,765.65**	**1,776.24**	**1,818.85**	**-0.0%**
Biogenic energy combustion[9]								
Biomass	189.40	194.39	254.82	282.24	290.63	305.61	332.19	1.9%
Electric power sector	18.52	17.81	60.15	74.35	71.05	72.79	82.99	5.4%
Other sectors	170.88	176.57	194.68	207.89	219.58	232.82	249.20	1.2%
Biogenic waste	4.37	4.90	6.22	6.22	6.23	6.23	6.23	0.8%
Biofuels heat and coproducts	80.21	63.03	76.56	76.49	79.37	91.26	128.24	2.5%
Ethanol	74.92	74.85	95.83	92.45	88.48	85.70	86.13	0.5%
Biodiesel	2.42	8.63	11.55	11.68	11.66	11.66	11.68	1.0%
Liquids from biomass	0.00	0.00	1.47	3.15	7.35	20.07	55.90	- -
Renewable diesel and gasoline	0.50	0.20	1.81	1.82	1.82	1.82	1.81	7.9%
Total	**351.81**	**346.01**	**448.26**	**474.05**	**485.54**	**522.35**	**622.19**	**2.0%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, and video game consoles.
[3]Includes desktop and laptop computers, monitors, printers, speakers, networking equipment, and uninterruptible power supplies.
[4]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[5]Includes emissions related to fuel consumption for district services.
[6] Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[7]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[8]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[9]By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 emissions and emission factors: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/10) (Washington, DC, October 2011). 2011 emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A20. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Real gross domestic product	**13,063**	**13,299**	**16,859**	**18,985**	**21,355**	**24,095**	**27,277**	**2.5%**
Components of real gross domestic product								
Real consumption	9,196	9,429	11,528	12,792	14,243	15,941	17,917	2.2%
Real investment	1,658	1,744	2,909	3,363	3,914	4,582	5,409	4.0%
Real government spending	2,606	2,524	2,446	2,529	2,659	2,803	2,980	0.6%
Real exports	1,666	1,777	3,016	4,026	5,214	6,658	8,357	5.5%
Real imports	2,085	2,185	2,927	3,515	4,311	5,308	6,518	3.8%
Energy intensity								
(thousand Btu per 2005 dollar of GDP)								
Delivered energy	5.47	5.34	4.39	3.92	3.48	3.13	2.85	-2.1%
Total energy	7.53	7.35	5.99	5.39	4.81	4.33	3.95	-2.1%
Price indices								
GDP chain-type price index (2005=1.000)	1.110	1.134	1.307	1.429	1.564	1.713	1.871	1.7%
Consumer price index (1982-4=1.00)								
All-urban	2.18	2.25	2.66	2.94	3.27	3.63	4.04	2.0%
Energy commodities and services	2.12	2.44	2.70	3.09	3.53	4.11	4.86	2.4%
Wholesale price index (1982=1.00)								
All commodities	1.85	2.01	2.22	2.40	2.59	2.82	3.10	1.5%
Fuel and power	1.86	2.16	2.48	2.91	3.38	4.02	4.90	2.9%
Metals and metal products	2.08	2.26	2.52	2.66	2.83	2.99	3.16	1.2%
Industrial commodities excluding energy	1.83	1.93	2.12	2.23	2.34	2.45	2.57	1.0%
Interest rates (percent, nominal)								
Federal funds rate	0.17	0.10	4.04	4.09	3.97	3.84	3.74	- -
10-year treasury note	3.21	2.79	4.88	4.97	4.95	4.91	4.86	- -
AA utility bond rate	5.23	4.78	6.91	7.10	7.21	7.35	7.39	- -
Value of shipments (billion 2005 dollars)								
Service sectors	20,771	21,168	26,492	29,715	32,624	35,511	38,529	2.1%
Total industrial	5,842	6,019	7,894	8,548	9,087	9,779	10,616	2.0%
Agriculture, mining, and construction	1,585	1,582	2,211	2,295	2,375	2,494	2,644	1.8%
Manufacturing	4,257	4,438	5,683	6,253	6,712	7,285	7,972	2.0%
Energy-intensive	1,592	1,615	1,893	1,993	2,027	2,077	2,144	1.0%
Non-energy-intensive	2,665	2,823	3,790	4,261	4,685	5,208	5,828	2.5%
Total shipments	**26,613**	**27,187**	**34,385**	**38,264**	**41,711**	**45,289**	**49,145**	**2.1%**
Population and employment (millions)								
Population, with armed forces overseas	310.1	312.4	340.5	356.5	372.4	388.3	404.4	0.9%
Population, aged 16 and over	244.6	247.0	269.5	282.8	296.3	309.8	322.9	0.9%
Population, over age 65	40.6	41.6	55.4	64.5	72.7	78.1	81.8	2.4%
Employment, nonfarm	129.8	131.3	149.2	153.7	160.8	166.7	174.0	1.0%
Employment, manufacturing	11.5	11.7	12.4	12.2	11.2	10.5	9.9	-0.6%
Key labor indicators								
Labor force (millions)	153.9	153.6	164.7	169.3	174.9	182.3	190.7	0.7%
Nonfarm labor productivity (1992=1.00)	1.09	1.10	1.25	1.39	1.54	1.70	1.88	1.9%
Unemployment rate (percent)	9.62	8.95	5.49	5.27	5.32	5.33	5.24	- -
Key indicators for energy demand								
Real disposable personal income	10,017	10,150	12,655	14,259	15,948	17,752	19,785	2.3%
Housing starts (millions)	0.64	0.66	1.89	1.90	1.89	1.89	1.89	3.7%
Commercial floorspace (billion square feet)	81.1	81.7	89.1	93.9	98.1	103.0	108.8	1.0%
Unit sales of light-duty vehicles (millions)	11.55	12.73	16.85	17.16	17.74	18.20	19.21	1.4%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2010 and 2011: IHS Global Insight, Global Insight Industry and Employment models, August 2012. **Projections:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System run REF2013.D102312A.

Table A21. International liquids supply and disposition summary
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Crude oil spot prices								
(2011 dollars per barrel)								
Brent	81.31	111.26	105.57	117.36	130.47	145.41	162.68	1.3%
West Texas Intermediate	81.08	94.86	103.57	115.36	128.47	143.41	160.68	1.8%
(nominal dollars per barrel)								
Brent	79.61	111.26	121.73	147.90	180.04	219.73	268.50	3.1%
West Texas Intermediate	79.39	94.86	119.43	145.38	177.28	216.70	265.20	3.6%
Liquids consumption[1]								
OECD								
United States (50 states)	18.90	18.68	19.49	19.16	18.72	18.55	18.64	0.0%
United States territories	0.25	0.28	0.32	0.34	0.36	0.36	0.37	1.0%
Canada	2.22	2.29	2.21	2.18	2.18	2.21	2.30	0.0%
Mexico and Chile	2.40	2.41	2.66	2.83	3.05	3.26	3.47	1.3%
OECD Europe[2]	14.80	14.28	13.81	13.85	13.96	14.10	14.21	0.0%
Japan	4.37	4.46	4.41	4.33	4.25	4.15	3.94	-0.4%
South Korea	2.25	2.32	2.56	2.61	2.66	2.69	2.74	0.6%
Australia and New Zealand	1.11	1.12	1.19	1.19	1.22	1.25	1.30	0.5%
Total OECD	**46.28**	**45.83**	**46.63**	**46.48**	**46.40**	**46.57**	**46.96**	**0.1%**
Non-OECD								
Russia	2.98	3.13	3.53	3.65	3.83	3.95	3.95	0.8%
Other Europe and Eurasia[3]	1.82	2.27	2.38	2.44	2.63	2.84	3.07	1.0%
China	9.33	9.85	13.29	14.71	15.58	16.64	17.59	2.0%
India	3.26	3.28	4.27	4.92	5.61	6.25	6.81	2.6%
Other Asia[4]	7.14	6.87	7.88	8.53	9.30	10.19	11.25	1.7%
Middle East	6.74	7.51	8.40	8.57	8.92	9.35	9.78	0.9%
Africa	3.37	3.31	3.63	3.82	4.05	4.32	4.49	1.1%
Brazil	2.62	2.59	3.01	3.12	3.37	3.62	4.00	1.5%
Other Central and South America	3.21	3.37	3.42	3.52	3.71	3.92	4.02	0.6%
Total non-OECD	**40.46**	**42.18**	**49.82**	**53.27**	**57.00**	**61.07**	**64.97**	**1.5%**
Total liquids consumption	**86.75**	**88.01**	**96.45**	**99.75**	**103.41**	**107.64**	**111.93**	**0.8%**
Liquids production								
OPEC[5]								
Middle East	23.77	25.40	26.65	27.91	29.88	32.63	35.09	1.1%
North Africa	3.76	2.39	3.27	3.27	3.48	3.77	3.96	1.8%
West Africa	4.45	4.31	5.33	5.47	5.61	5.75	5.89	1.1%
South America	2.88	2.99	3.09	3.05	3.01	3.06	3.20	0.2%
Total OPEC	**34.85**	**35.08**	**38.34**	**39.69**	**41.98**	**45.20**	**48.13**	**1.1%**
Non-OPEC								
OECD								
United States (50 states)	9.44	10.11	12.74	12.10	11.42	11.52	11.67	0.5%
Canada	3.58	3.66	5.09	5.60	5.91	6.09	6.14	1.8%
Mexico and Chile	3.01	2.99	1.96	1.84	1.98	2.04	2.12	-1.2%
OECD Europe[2]	4.58	4.19	3.38	3.08	2.84	2.93	3.36	-0.8%
Japan	0.18	0.18	0.17	0.18	0.18	0.19	0.19	0.2%
Australia and New Zealand	0.66	0.58	0.54	0.53	0.56	0.78	0.87	1.4%
Total OECD	**21.45**	**21.71**	**23.88**	**23.33**	**22.90**	**23.54**	**24.35**	**0.4%**
Non-OECD								
Russia	10.14	10.23	10.75	10.95	11.43	11.94	11.48	0.4%
Other Europe and Eurasia[3]	3.24	3.26	4.20	4.85	4.85	4.83	5.24	1.6%
China	4.34	4.34	4.59	5.02	5.50	5.54	5.42	0.8%
Other Asia[4]	3.82	3.74	3.55	3.34	3.09	2.81	2.87	-0.9%
Middle East	1.57	1.43	1.23	1.22	1.09	0.91	0.89	-1.6%
Africa	2.68	2.68	3.08	3.14	3.10	2.95	3.18	0.6%
Brazil	2.52	2.53	4.35	5.63	6.96	7.43	7.61	3.9%
Other Central and South America	2.08	2.17	2.40	2.51	2.46	2.43	2.69	0.7%
Total non-OECD	**30.39**	**30.39**	**34.15**	**36.65**	**38.47**	**38.84**	**39.37**	**0.9%**
Total liquids production	**86.70**	**87.18**	**96.38**	**99.68**	**103.35**	**107.58**	**111.85**	**0.9%**
OPEC liquids market share (percent)	40.2	40.2	39.8	39.8	40.6	42.0	43.0	- -

Table A21. International liquids supply and disposition summary (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case 2010	2011	2020	2025	2030	2035	2040	Annual growth 2011-2040 (percent)
Selected world liquids production subtotals:								
Petroleum[6]								
Crude oil and equivalents[7]	74.11	74.08	80.28	82.51	85.26	87.59	90.90	0.7%
Tight oil	0.82	1.27	3.83	4.52	4.91	5.54	6.10	5.6%
Bitumen[8]	1.65	1.74	3.00	3.52	3.95	4.21	4.26	3.1%
Natural gas plant liquids	8.53	8.66	10.88	11.52	11.75	12.40	12.88	1.4%
Refinery processing gain[9]	2.27	2.28	2.20	2.31	2.50	2.69	2.82	0.7%
Liquids from renewable sources[10]	1.31	1.33	2.08	2.29	2.49	2.67	2.93	2.8%
Liquids from coal[11]	0.17	0.18	0.40	0.68	0.95	1.17	1.19	6.7%
Liquids from natural gas[12]	0.07	0.12	0.39	0.45	0.48	0.51	0.55	5.4%
Liquids from kerogen[13]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.6%
Petroleum production[6]								
OPEC[5]								
Middle East	23.76	25.34	26.44	27.66	29.64	32.38	34.84	1.1%
North Africa	3.76	2.39	3.27	3.27	3.48	3.77	3.96	1.8%
West Africa	4.45	4.31	5.30	5.44	5.58	5.72	5.86	1.1%
South America	2.88	2.99	3.09	3.05	3.01	3.06	3.20	0.2%
Total OPEC	**34.85**	**35.03**	**38.10**	**39.42**	**41.71**	**44.93**	**47.86**	**1.1%**
Non-OPEC								
OECD								
United States (50 states)	8.66	9.25	11.64	10.95	10.21	10.20	10.08	0.3%
Canada	3.56	3.64	5.07	5.57	5.87	6.05	6.10	1.8%
Mexico and Chile	3.01	2.99	1.96	1.84	1.98	2.04	2.12	-1.2%
OECD Europe[2]	4.36	3.98	3.16	2.85	2.60	2.67	3.09	-0.9%
Japan	0.17	0.17	0.16	0.17	0.18	0.18	0.18	0.1%
Australia and New Zealand	0.66	0.57	0.53	0.52	0.55	0.77	0.86	1.4%
Total OECD	**20.43**	**20.60**	**22.52**	**21.90**	**21.39**	**21.90**	**22.43**	**0.3%**
Non-OECD								
Russia	10.14	10.23	10.75	10.94	11.42	11.94	11.47	0.4%
Other Europe and Eurasia[3]	3.24	3.25	4.19	4.84	4.84	4.82	5.23	1.7%
China	4.30	4.30	4.44	4.65	4.83	4.64	4.52	0.2%
Other Asia[4]	3.76	3.67	3.42	3.13	2.88	2.59	2.65	-1.1%
Middle East	1.57	1.43	1.23	1.22	1.09	0.91	0.89	-1.6%
Africa	2.46	2.47	2.75	2.80	2.74	2.60	2.82	0.5%
Brazil	2.19	2.25	3.57	4.70	5.92	6.30	6.48	3.7%
Other Central and South America	2.01	2.09	2.33	2.43	2.38	2.34	2.60	0.8%
Total non-OECD	**29.68**	**29.69**	**32.69**	**34.73**	**36.11**	**36.15**	**36.66**	**0.7%**
Total petroleum production	**84.96**	**85.31**	**93.32**	**96.05**	**99.20**	**102.99**	**106.96**	**0.8%**
OPEC petroleum market share (percent)	41.0	41.1	40.8	41.0	42.0	43.6	44.7	- -

[1]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes production of crude oil (including lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands)), natural gas plant liquids, refinery gains, and other hydrogen and hydrocarbons for refinery feedstocks.
[7]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[8]Includes diluted and upgraded/synthetic bitumen (syncrude).
[9]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[10]Includes liquids produced from energy crops.
[11]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[12]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[13]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
- - = Not applicable.
Note: Ethanol is represented in motor gasoline equivalent barrels. Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 crude oil spot prices: Thomson Reuters. 2010 quantities derived from: Energy Information Administration (EIA), International Energy Statistics database as of October 2012. **2011 quantities and projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A and EIA, Generate World Oil Balance Model.

Economic growth case comparisons

Table B1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2011	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Production										
Crude oil and lease condensate	12.16	15.95	15.95	15.99	12.93	13.47	13.79	12.69	13.12	13.37
Natural gas plant liquids	2.88	4.10	4.14	4.20	3.80	3.85	3.92	3.86	3.89	3.95
Dry natural gas	23.51	26.58	27.19	27.80	29.33	30.44	31.92	32.46	33.87	35.32
Coal[1]	22.21	20.30	21.74	22.90	21.61	23.25	24.28	22.01	23.54	24.64
Nuclear / uranium[2]	8.26	9.16	9.25	9.25	9.41	9.49	9.60	8.91	9.44	11.47
Hydropower	3.17	2.81	2.83	2.84	2.84	2.87	2.90	2.90	2.92	2.95
Biomass[3]	4.05	4.77	5.00	5.06	5.09	5.42	5.60	5.95	6.96	7.48
Other renewable energy[4]	1.58	2.19	2.22	2.51	2.36	2.50	3.14	2.81	3.84	5.86
Other[5]	1.20	0.80	0.83	0.86	0.82	0.88	0.93	0.82	0.89	0.96
Total	**79.02**	**86.65**	**89.16**	**91.40**	**88.18**	**92.18**	**96.08**	**92.41**	**98.46**	**105.99**
Imports										
Crude oil	19.46	13.71	15.02	16.14	14.38	16.33	18.27	14.17	16.89	19.70
Liquid fuels and other petroleum[6]	5.24	5.44	5.55	5.60	5.19	5.33	5.59	4.81	4.82	5.70
Natural gas[7]	3.54	2.46	2.58	2.70	2.42	2.63	2.88	1.97	2.01	2.07
Other imports[8]	0.43	0.11	0.11	0.16	0.09	0.13	0.34	0.70	0.84	1.49
Total	**28.66**	**21.72**	**23.26**	**24.60**	**22.07**	**24.41**	**27.08**	**21.64**	**24.55**	**28.95**
Exports										
Liquid fuels and other petroleum[9]	6.08	5.41	5.37	5.28	5.33	5.25	5.33	5.72	5.71	5.86
Natural gas[10]	1.52	2.69	2.67	2.65	5.38	4.71	4.63	6.50	5.56	5.38
Coal	2.75	3.11	3.13	3.10	3.50	3.51	3.51	3.79	3.79	3.82
Total	**10.35**	**11.21**	**11.17**	**11.03**	**14.22**	**13.47**	**13.47**	**16.01**	**15.06**	**15.07**
Discrepancy[11]	**-0.36**	**0.21**	**0.21**	**0.20**	**0.32**	**0.30**	**0.41**	**0.29**	**0.32**	**0.50**
Consumption										
Liquid fuels and other petroleum[12]	37.02	35.91	37.54	39.02	33.05	36.08	38.64	32.32	36.07	40.00
Natural gas	24.91	26.08	26.77	27.52	26.05	27.95	29.75	27.60	29.83	31.49
Coal[13]	19.66	17.17	18.59	19.74	18.11	19.70	20.88	18.73	20.35	21.97
Nuclear / uranium[2]	8.26	9.16	9.25	9.25	9.41	9.49	9.60	8.91	9.44	11.47
Hydropower	3.17	2.81	2.83	2.84	2.84	2.87	2.90	2.90	2.92	2.95
Biomass[14]	2.74	3.33	3.53	3.57	3.64	3.94	4.09	4.18	4.91	5.33
Other renewable energy[4]	1.58	2.19	2.22	2.51	2.36	2.50	3.14	2.81	3.84	5.86
Other[15]	0.35	0.31	0.31	0.31	0.26	0.28	0.28	0.29	0.29	0.30
Total	**97.70**	**96.95**	**101.04**	**104.76**	**95.72**	**102.81**	**109.28**	**97.74**	**107.64**	**119.37**
Prices (2011 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.26	103.47	105.57	107.22	127.05	130.47	133.60	157.47	162.68	168.70
West Texas Intermediate	94.86	101.51	103.57	105.19	125.11	128.47	131.55	155.53	160.68	166.63
Natural gas at Henry Hub (dollars per million Btu)	3.98	3.78	4.13	4.54	5.11	5.40	6.03	7.22	7.83	8.44
Coal (dollars per ton) at the minemouth[16]	41.16	49.48	49.26	49.38	55.65	55.64	56.52	60.63	61.28	62.91
Coal (dollars per million Btu) at the minemouth[16]	2.04	2.46	2.45	2.47	2.78	2.79	2.83	3.04	3.08	3.17
Average end-use[17]	2.57	2.73	2.77	2.82	3.03	3.10	3.17	3.34	3.42	3.53
Average electricity (cents per kilowatthour)	9.9	9.5	9.4	9.5	9.6	9.7	10.0	10.4	10.8	11.2

Table B1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2011	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.26	128.51	121.73	120.63	223.19	180.04	173.06	395.38	268.50	249.71
West Texas Intermediate	94.86	126.08	119.43	118.34	219.76	177.28	170.41	390.52	265.20	246.64
Natural gas at Henry Hub (dollars per million Btu)	3.98	4.69	4.77	5.11	8.98	7.45	7.82	18.12	12.92	12.49
Coal (dollars per ton)										
at the minemouth[16]	41.16	61.45	56.81	55.55	97.75	76.78	73.22	152.24	101.14	93.11
Coal (dollars per million Btu)										
at the minemouth[16]	2.04	3.06	2.83	2.77	4.88	3.85	3.67	7.64	5.08	4.70
Average end-use[17]	2.57	3.38	3.19	3.18	5.33	4.28	4.11	8.38	5.65	5.23
Average electricity (cents per kilowatthour)	9.9	11.8	10.8	10.7	16.8	13.4	13.0	26.1	17.8	16.6

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2011 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012). 2011 petroleum supply values: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2011 crude oil spot prices: Thomson Reuters. Other 2011 coal values: *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012). Other 2011 values: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWMACRO.D110912A, REF2013.D102312A, and HIGHMACRO.D110912A.

Table B2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2011	Projections 2020 Low economic growth	2020 Reference	2020 High economic growth	2030 Low economic growth	2030 Reference	2030 High economic growth	2040 Low economic growth	2040 Reference	2040 High economic growth
Energy consumption										
Residential										
Propane	0.53	0.52	0.52	0.53	0.50	0.52	0.55	0.49	0.52	0.57
Kerosene	0.02	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	0.59	0.51	0.51	0.51	0.40	0.40	0.40	0.32	0.32	0.32
Liquid fuels and other petroleum subtotal	1.14	1.04	1.05	1.05	0.91	0.93	0.96	0.82	0.86	0.91
Natural gas	4.83	4.58	4.62	4.69	4.27	4.46	4.67	3.93	4.23	4.57
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Renewable energy[1]	0.45	0.43	0.44	0.45	0.42	0.45	0.47	0.42	0.45	0.50
Electricity	4.86	4.67	4.84	5.02	4.97	5.36	5.85	5.38	6.03	6.90
Delivered energy	**11.28**	**10.72**	**10.95**	**11.21**	**10.58**	**11.20**	**11.96**	**10.55**	**11.57**	**12.88**
Electricity related losses	10.20	9.30	9.66	10.02	9.80	10.45	11.30	10.27	11.50	13.30
Total	**21.48**	**20.02**	**20.62**	**21.24**	**20.38**	**21.65**	**23.26**	**20.82**	**23.08**	**26.17**
Commercial										
Propane	0.14	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Distillate fuel oil	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.30	0.30	0.30
Residual fuel oil	0.07	0.10	0.09	0.09	0.09	0.09	0.09	0.08	0.09	0.09
Liquid fuels and other petroleum subtotal	0.69	0.66	0.65	0.65	0.64	0.64	0.64	0.62	0.63	0.63
Natural gas	3.23	3.42	3.40	3.37	3.51	3.50	3.49	3.65	3.68	3.72
Coal	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.50	4.68	4.72	4.73	5.16	5.22	5.27	5.61	5.72	5.82
Delivered energy	**8.60**	**8.93**	**8.95**	**8.93**	**9.48**	**9.54**	**9.57**	**10.06**	**10.21**	**10.35**
Electricity related losses	9.45	9.30	9.42	9.44	10.18	10.18	10.16	10.72	10.92	11.22
Total	**18.05**	**18.23**	**18.37**	**18.38**	**19.66**	**19.72**	**19.73**	**20.78**	**21.13**	**21.57**
Industrial[4]										
Liquefied petroleum gases	2.10	2.33	2.46	2.56	2.20	2.47	2.59	2.02	2.30	2.57
Propylene	0.40	0.52	0.56	0.58	0.46	0.52	0.55	0.41	0.46	0.51
Motor gasoline[2]	0.27	0.29	0.32	0.35	0.28	0.32	0.35	0.28	0.32	0.36
Distillate fuel oil	1.21	1.10	1.22	1.37	1.02	1.18	1.35	1.06	1.22	1.41
Residual fuel oil	0.11	0.10	0.11	0.12	0.10	0.11	0.12	0.10	0.11	0.12
Petrochemical feedstocks	0.88	1.01	1.03	1.06	1.03	1.08	1.13	1.02	1.09	1.16
Other petroleum[5]	3.61	3.26	3.54	3.86	3.04	3.46	3.87	3.16	3.65	4.13
Liquid fuels and other petroleum subtotal	8.57	8.60	9.25	9.88	8.11	9.14	9.96	8.04	9.16	10.26
Natural gas	6.92	7.41	7.86	8.28	7.13	7.97	8.70	7.01	8.08	9.38
Natural-gas-to-liquids heat and power	0.00	0.07	0.13	0.13	0.11	0.21	0.21	0.16	0.33	0.36
Lease and plant fuel[6]	1.42	1.54	1.57	1.60	1.74	1.73	1.80	1.96	1.97	2.07
Natural gas subtotal	8.34	9.02	9.56	10.01	8.98	9.91	10.72	9.13	10.38	11.81
Metallurgical coal	0.56	0.55	0.60	0.68	0.45	0.52	0.63	0.38	0.46	0.63
Other industrial coal	1.04	0.96	1.00	1.04	0.94	1.00	1.06	0.97	1.05	1.14
Coal-to-liquids heat and power	0.00	0.00	0.00	0.11	0.00	0.09	0.17	0.10	0.15	0.29
Net coal coke imports	0.01	-0.01	-0.01	-0.01	-0.04	-0.04	-0.05	-0.05	-0.05	-0.06
Coal subtotal	1.62	1.50	1.58	1.81	1.35	1.57	1.81	1.41	1.61	2.00
Biofuels heat and coproducts	0.67	0.80	0.82	0.84	0.83	0.85	0.87	1.14	1.37	1.40
Renewable energy[7]	1.51	1.58	1.72	1.80	1.70	1.97	2.11	1.94	2.28	2.53
Electricity	3.33	3.65	3.95	4.22	3.49	3.96	4.35	3.42	3.91	4.55
Delivered energy	**24.04**	**25.15**	**26.87**	**28.56**	**24.48**	**27.40**	**29.83**	**25.09**	**28.71**	**32.55**
Electricity related losses	6.99	7.25	7.89	8.43	6.89	7.72	8.40	6.53	7.45	8.77
Total	**31.03**	**32.40**	**34.76**	**36.99**	**31.37**	**35.11**	**38.22**	**31.62**	**36.16**	**41.32**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2011	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Transportation										
Propane	0.06	0.06	0.06	0.06	0.06	0.07	0.08	0.07	0.08	0.10
E85[8]	0.05	0.09	0.08	0.08	0.28	0.16	0.15	0.26	0.17	0.22
Motor gasoline[2]	16.31	14.49	14.88	15.14	12.01	13.06	13.70	11.10	12.64	13.61
Jet fuel[9]	3.01	3.08	3.11	3.14	3.22	3.28	3.34	3.32	3.42	3.53
Distillate fuel oil[10]	5.91	6.72	7.28	7.83	6.64	7.61	8.60	6.90	7.90	9.51
Residual fuel oil	0.82	0.84	0.84	0.85	0.85	0.86	0.86	0.86	0.87	0.88
Other petroleum[11]	0.17	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17
Liquid fuels and other petroleum subtotal	26.32	25.44	26.42	27.26	23.21	25.20	26.90	22.66	25.24	28.01
Pipeline fuel natural gas	0.70	0.70	0.71	0.73	0.71	0.74	0.78	0.74	0.78	0.80
Compressed / liquefied natural gas	0.04	0.07	0.08	0.08	0.27	0.26	0.25	0.94	1.05	1.29
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.05	0.06	0.07	0.07
Delivered energy	**27.09**	**26.24**	**27.24**	**28.09**	**24.24**	**26.25**	**27.98**	**24.40**	**27.14**	**30.18**
Electricity related losses	0.05	0.06	0.06	0.06	0.08	0.09	0.09	0.12	0.13	0.14
Total	**27.13**	**26.29**	**27.30**	**28.15**	**24.32**	**26.33**	**28.07**	**24.52**	**27.27**	**30.31**
Delivered energy consumption for all sectors										
Liquefied petroleum gases	2.82	3.07	3.21	3.31	2.93	3.23	3.38	2.75	3.08	3.41
Propylene	0.40	0.52	0.56	0.58	0.46	0.52	0.55	0.41	0.46	0.51
E85[8]	0.05	0.09	0.08	0.08	0.28	0.16	0.15	0.26	0.17	0.22
Motor gasoline[2]	16.64	14.84	15.26	15.54	12.35	13.43	14.12	11.44	13.03	14.03
Jet fuel[9]	3.01	3.08	3.11	3.14	3.22	3.28	3.34	3.32	3.42	3.53
Kerosene	0.03	0.03	0.03	0.03	0.02	0.02	0.03	0.02	0.02	0.03
Distillate fuel oil	8.12	8.66	9.35	10.04	8.37	9.51	10.67	8.58	9.74	11.54
Residual fuel oil	1.01	1.04	1.05	1.06	1.03	1.05	1.07	1.04	1.07	1.09
Petrochemical feedstocks	0.88	1.01	1.03	1.06	1.03	1.08	1.13	1.02	1.09	1.16
Other petroleum[12]	3.77	3.40	3.69	4.00	3.19	3.61	4.02	3.31	3.80	4.29
Liquid fuels and other petroleum subtotal	36.72	35.74	37.37	38.84	32.87	35.90	38.45	32.14	35.88	39.80
Natural gas	15.03	15.48	15.95	16.42	15.19	16.19	17.11	15.52	17.05	18.95
Natural-gas-to-liquids heat and power	0.00	0.07	0.13	0.13	0.11	0.21	0.21	0.16	0.33	0.36
Lease and plant fuel[6]	1.42	1.54	1.57	1.60	1.74	1.73	1.80	1.96	1.97	2.07
Pipeline natural gas	0.70	0.70	0.71	0.73	0.71	0.74	0.78	0.74	0.78	0.80
Natural gas subtotal	17.15	17.79	18.36	18.88	17.75	18.87	19.90	18.39	20.13	22.19
Metallurgical coal	0.56	0.55	0.60	0.68	0.45	0.52	0.63	0.38	0.46	0.63
Other coal	1.10	1.02	1.06	1.10	1.00	1.06	1.11	1.03	1.11	1.20
Coal-to-liquids heat and power	0.00	0.00	0.00	0.11	0.00	0.09	0.17	0.10	0.15	0.29
Net coal coke imports	0.01	-0.01	-0.01	-0.01	-0.04	-0.04	-0.05	-0.05	-0.05	-0.06
Coal subtotal	1.67	1.56	1.64	1.87	1.41	1.63	1.87	1.47	1.67	2.06
Biofuels heat and coproducts	0.67	0.80	0.82	0.84	0.83	0.85	0.87	1.14	1.37	1.40
Renewable energy[13]	2.08	2.13	2.28	2.37	2.25	2.54	2.71	2.48	2.86	3.16
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity	12.71	13.03	13.54	14.01	13.66	14.59	15.52	14.48	15.72	17.34
Delivered energy	**71.01**	**71.04**	**74.01**	**76.80**	**68.77**	**74.38**	**79.33**	**70.10**	**77.63**	**85.95**
Electricity related losses	26.69	25.91	27.03	27.96	26.95	28.43	29.95	27.64	30.00	33.42
Total	**97.70**	**96.95**	**101.04**	**104.76**	**95.72**	**102.81**	**109.28**	**97.74**	**107.64**	**119.37**
Electric power[14]										
Distillate fuel oil	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Residual fuel oil	0.23	0.09	0.10	0.10	0.10	0.10	0.11	0.10	0.11	0.12
Liquid fuels and other petroleum subtotal	0.30	0.17	0.18	0.18	0.17	0.18	0.19	0.18	0.19	0.20
Natural gas	7.76	8.29	8.40	8.65	8.30	9.08	9.84	9.21	9.70	9.30
Steam coal	17.99	15.61	16.95	17.87	16.71	18.07	19.01	17.26	18.68	19.91
Nuclear / uranium[15]	8.26	9.16	9.25	9.25	9.41	9.49	9.60	8.91	9.44	11.47
Renewable energy[16]	4.74	5.39	5.49	5.72	5.76	5.93	6.55	6.27	7.44	9.59
Electricity imports	0.13	0.08	0.08	0.08	0.03	0.05	0.05	0.06	0.06	0.07
Total[17]	**39.40**	**38.94**	**40.57**	**41.97**	**40.61**	**43.02**	**45.47**	**42.12**	**45.73**	**50.76**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2011	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Total energy consumption										
Liquefied petroleum gases	2.82	3.07	3.21	3.31	2.93	3.23	3.38	2.75	3.08	3.41
Propylene	0.40	0.52	0.56	0.58	0.46	0.52	0.55	0.41	0.46	0.51
E85[8]	0.05	0.09	0.08	0.08	0.28	0.16	0.15	0.26	0.17	0.22
Motor gasoline[2]	16.64	14.84	15.26	15.54	12.35	13.43	14.12	11.44	13.03	14.03
Jet fuel[9]	3.01	3.08	3.11	3.14	3.22	3.28	3.34	3.32	3.42	3.53
Kerosene	0.03	0.03	0.03	0.03	0.02	0.02	0.03	0.02	0.02	0.03
Distillate fuel oil	8.18	8.74	9.43	10.12	8.45	9.59	10.75	8.65	9.82	11.62
Residual fuel oil	1.24	1.13	1.15	1.16	1.13	1.15	1.17	1.15	1.17	1.21
Petrochemical feedstocks	0.88	1.01	1.03	1.06	1.03	1.08	1.13	1.02	1.09	1.16
Other petroleum[12]	3.77	3.40	3.69	4.00	3.19	3.61	4.02	3.31	3.80	4.29
Liquid fuels and other petroleum subtotal	37.02	35.91	37.54	39.02	33.05	36.08	38.64	32.32	36.07	40.00
Natural gas	22.79	23.78	24.36	25.07	23.49	25.27	26.96	24.73	26.75	28.26
Natural-gas-to-liquids heat and power	0.00	0.07	0.13	0.13	0.11	0.21	0.21	0.16	0.33	0.36
Lease and plant fuel[6]	1.42	1.54	1.57	1.60	1.74	1.73	1.80	1.96	1.97	2.07
Pipeline natural gas	0.70	0.70	0.71	0.73	0.71	0.74	0.78	0.74	0.78	0.80
Natural gas subtotal	24.91	26.08	26.77	27.52	26.05	27.95	29.75	27.60	29.83	31.49
Metallurgical coal	0.56	0.55	0.60	0.68	0.45	0.52	0.63	0.38	0.46	0.63
Other coal	19.09	16.63	18.01	18.97	17.70	19.12	20.13	18.28	19.79	21.11
Coal-to-liquids heat and power	0.00	0.00	0.00	0.11	0.00	0.09	0.17	0.10	0.15	0.29
Net coal coke imports	0.01	-0.01	-0.01	-0.01	-0.04	-0.04	-0.05	-0.05	-0.05	-0.06
Coal subtotal	19.66	17.17	18.59	19.74	18.11	19.70	20.88	18.73	20.35	21.97
Nuclear / uranium[15]	8.26	9.16	9.25	9.25	9.41	9.49	9.60	8.91	9.44	11.47
Biofuels heat and coproducts	0.67	0.80	0.82	0.84	0.83	0.85	0.87	1.14	1.37	1.40
Renewable energy[18]	6.82	7.53	7.77	8.09	8.01	8.47	9.25	8.75	10.30	12.74
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity imports	0.13	0.08	0.08	0.08	0.03	0.05	0.05	0.06	0.06	0.07
Total	**97.70**	**96.95**	**101.04**	**104.76**	**95.72**	**102.81**	**109.28**	**97.74**	**107.64**	**119.37**
Energy use and related statistics										
Delivered energy use	71.01	71.04	74.01	76.80	68.77	74.38	79.33	70.10	77.63	85.95
Total energy use	97.70	96.95	101.04	104.76	95.72	102.81	109.28	97.74	107.64	119.37
Ethanol consumed in motor gasoline and E85	1.17	1.31	1.34	1.37	1.22	1.24	1.29	1.13	1.21	1.32
Population (millions)	312.38	338.25	340.45	342.94	367.06	372.41	378.73	395.19	404.39	415.38
Gross domestic product (billion 2005 dollars)	13,299	15,717	16,859	17,754	18,703	21,355	23,232	23,283	27,277	30,552
Carbon dioxide emissions (million metric tons)	5,471	5,192	5,455	5,685	5,095	5,523	5,882	5,197	5,691	6,163

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2012. 2011 carbon dioxide emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWMACRO.D110912A, REF2013.D102312A, and HIGHMACRO.D110912A.

Table B3. Energy prices by sector and source

(2010 dollars per million Btu, unless otherwise noted)

Sector and source	2011	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Propane	25.06	22.83	23.41	23.91	25.25	25.73	26.28	27.58	27.99	28.56
Distillate fuel oil	26.38	26.37	26.91	27.27	30.41	31.26	32.06	35.37	36.54	38.26
Natural gas	10.80	11.37	11.78	12.30	12.88	13.37	14.11	15.56	16.36	17.95
Electricity	34.34	34.22	33.62	33.85	34.42	34.56	35.14	36.31	37.10	37.97
Commercial										
Propane	22.10	19.32	20.04	20.66	22.35	22.97	23.68	25.39	25.94	26.76
Distillate fuel oil	25.87	23.83	24.26	24.60	27.76	28.51	29.24	32.62	33.74	35.73
Residual fuel oil	19.17	14.53	14.82	15.02	18.08	18.77	19.01	22.92	23.41	24.06
Natural gas	8.84	9.09	9.47	9.94	10.28	10.70	11.33	12.53	13.21	14.14
Electricity	29.98	28.71	28.57	29.21	27.98	28.65	29.76	30.39	31.75	33.42
Industrial[1]										
Propane	22.54	19.74	20.51	21.15	22.96	23.64	24.37	26.16	26.78	28.08
Distillate fuel oil	26.50	24.31	24.67	25.00	28.22	28.91	29.58	33.09	34.16	36.05
Residual fuel oil	18.86	16.89	17.19	17.41	20.52	21.09	21.34	25.37	25.78	26.36
Natural gas[2]	4.89	5.19	5.53	5.98	6.26	6.56	7.13	8.37	8.88	9.43
Metallurgical coal	7.01	8.81	8.75	8.74	10.12	10.09	10.13	11.03	11.11	11.32
Other industrial coal	3.43	3.44	3.44	3.47	3.66	3.71	3.77	3.99	4.06	4.12
Coal to liquids	- -	- -	- -	2.11	- -	2.55	2.60	2.90	2.95	2.90
Electricity	19.98	18.57	18.72	19.41	18.99	19.73	20.86	21.45	22.74	24.31
Transportation										
Propane	26.06	23.89	24.48	24.97	26.32	26.80	27.35	28.65	29.07	29.89
E85[3]	25.30	28.53	29.64	30.12	27.32	26.94	28.58	31.85	30.58	33.52
Motor gasoline[4]	28.70	27.57	27.84	28.24	30.16	30.73	31.28	35.10	36.18	37.96
Jet fuel[5]	22.49	21.10	21.50	21.81	25.48	26.03	26.70	30.65	31.07	32.93
Diesel fuel (distillate fuel oil)[6]	26.15	26.27	26.61	26.93	30.14	30.81	31.46	34.97	36.05	38.06
Residual fuel oil	17.83	14.64	14.91	15.13	17.92	18.34	18.74	21.98	22.45	23.37
Natural gas[7]	16.14	16.27	16.87	17.45	17.96	18.90	19.62	19.76	21.20	22.26
Electricity	32.77	29.28	29.60	30.42	30.50	31.53	32.82	33.31	35.07	36.84
Electric power[8]										
Distillate fuel oil	23.30	21.90	22.45	22.82	25.93	26.80	27.58	30.87	32.03	34.00
Residual fuel oil	15.97	24.65	24.94	25.22	29.03	29.36	29.79	34.04	34.54	35.34
Natural gas	4.77	4.54	4.90	5.34	5.69	6.05	6.66	7.86	8.38	8.79
Steam coal	2.38	2.47	2.52	2.57	2.81	2.87	2.92	3.13	3.20	3.27
Average price to all users[9]										
Propane	17.13	12.84	13.69	14.51	17.27	18.14	19.37	22.77	23.79	25.04
E85[3]	25.30	28.53	29.64	30.12	27.32	26.94	28.58	31.85	30.58	33.52
Motor gasoline[4]	28.47	27.57	27.84	28.24	30.15	30.72	31.28	35.10	36.17	37.95
Jet fuel[5]	22.49	21.10	21.50	21.81	25.48	26.03	26.70	30.65	31.07	32.93
Distillate fuel oil	26.18	25.90	26.25	26.57	29.80	30.48	31.15	34.64	35.73	37.72
Residual fuel oil	17.65	15.66	15.97	16.22	19.10	19.59	20.02	23.41	23.95	24.89
Natural gas	6.68	6.74	7.07	7.50	7.99	8.27	8.82	10.36	10.94	11.77
Metallurgical coal	7.01	8.81	8.75	8.74	10.12	10.09	10.13	11.03	11.11	11.32
Other coal	2.45	2.53	2.57	2.62	2.86	2.92	2.97	3.18	3.25	3.32
Coal to liquids	- -	- -	- -	2.11	- -	2.55	2.60	2.90	2.95	2.90
Electricity	29.03	27.85	27.50	27.92	28.03	28.41	29.31	30.49	31.58	32.86
Non-renewable energy expenditures by sector (billion 2011 dollars)										
Residential	248.08	237.55	243.44	254.57	251.11	271.05	299.14	281.74	319.63	372.95
Commercial	179.97	179.72	181.68	186.63	196.60	203.80	213.44	234.84	249.60	267.32
Industrial	225.18	233.96	259.03	287.38	253.14	294.99	337.55	296.17	353.70	430.16
Transportation	718.25	660.22	694.73	727.04	671.51	749.40	817.74	779.09	900.68	1,055.41
Total non-renewable expenditures	1,371.48	1,311.46	1,378.87	1,455.61	1,372.36	1,519.24	1,667.86	1,591.84	1,823.61	2,125.83
Transportation renewable expenditures	1.24	2.69	2.44	2.52	7.56	4.39	4.34	8.39	5.05	7.26
Total expenditures	**1,372.71**	**1,314.15**	**1,381.31**	**1,458.13**	**1,379.92**	**1,523.63**	**1,672.20**	**1,600.24**	**1,828.66**	**2,133.08**

Table B3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2011	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Propane	25.06	28.35	27.00	26.90	44.35	35.51	34.04	69.24	46.20	42.27
Distillate fuel oil	26.38	32.75	31.03	30.68	53.42	43.14	41.52	88.80	60.31	56.64
Natural gas	10.80	14.12	13.58	13.84	22.63	18.45	18.28	39.07	27.01	26.56
Electricity	34.34	42.50	38.76	38.08	60.47	47.69	45.53	91.16	61.23	56.21
Commercial										
Propane	22.10	24.00	23.11	23.24	39.26	31.70	30.67	63.74	42.82	39.60
Distillate fuel oil	25.87	29.60	27.97	27.68	48.76	39.34	37.87	81.91	55.68	52.88
Residual fuel oil	19.17	18.05	17.09	16.90	31.77	25.90	24.63	57.55	38.64	35.61
Natural gas	8.84	11.29	10.92	11.18	18.06	14.76	14.68	31.47	21.81	20.92
Electricity	29.98	35.65	32.94	32.86	49.15	39.54	38.56	76.30	52.40	49.46
Industrial[1]										
Propane	22.54	24.52	23.65	23.80	40.33	32.62	31.57	65.69	44.20	41.56
Distillate fuel oil	26.50	30.19	28.45	28.12	49.57	39.89	38.32	83.08	56.39	53.36
Residual fuel oil	18.86	20.98	19.82	19.59	36.05	29.10	27.65	63.69	42.55	39.02
Natural gas[2]	4.89	6.44	6.38	6.72	11.00	9.05	9.24	21.03	14.66	13.95
Metallurgical coal	7.01	10.94	10.09	9.83	17.78	13.92	13.12	27.68	18.34	16.76
Other industrial coal	3.43	4.27	3.97	3.91	6.43	5.12	4.88	10.03	6.70	6.10
Coal to liquids	- -	- -	- -	2.37	- -	3.52	3.36	7.28	4.87	4.30
Electricity	19.98	23.07	21.59	21.83	33.37	27.22	27.03	53.86	37.54	35.99
Transportation										
Propane	26.06	29.67	28.22	28.10	46.23	36.98	35.42	71.93	47.97	44.25
E85[3]	25.30	35.44	34.18	33.89	47.99	37.18	37.02	79.96	50.46	49.62
Motor gasoline[4]	28.70	34.25	32.10	31.77	52.98	42.41	40.52	88.14	59.72	56.19
Jet fuel[5]	22.49	26.21	24.79	24.54	44.75	35.92	34.59	76.97	51.27	48.75
Diesel fuel (distillate fuel oil)[6]	26.15	32.63	30.68	30.29	52.95	42.52	40.75	87.80	59.50	56.33
Residual fuel oil	17.83	18.18	17.19	17.02	31.48	25.31	24.28	55.18	37.06	34.59
Natural gas[7]	16.14	20.21	19.46	19.64	31.55	26.08	25.42	49.62	34.98	32.95
Electricity	32.77	36.36	34.13	34.22	53.57	43.51	42.52	83.64	57.88	54.52
Electric power[8]										
Distillate fuel oil	23.30	27.20	25.89	25.67	45.54	36.98	35.73	77.51	52.87	50.33
Residual fuel oil	15.97	30.62	28.76	28.38	51.00	40.52	38.59	85.47	57.01	52.31
Natural gas	4.77	5.64	5.65	6.01	9.99	8.35	8.62	19.73	13.83	13.01
Steam coal	2.38	3.06	2.90	2.89	4.93	3.96	3.78	7.86	5.28	4.84

Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2011	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Average price to all users[9]										
Propane	17.13	15.94	15.78	16.32	30.33	25.03	25.09	57.18	39.26	37.06
E85[3]	25.30	35.44	34.18	33.89	47.99	37.18	37.02	79.96	50.46	49.62
Motor gasoline[4]	28.47	34.24	32.10	31.77	52.97	42.40	40.51	88.13	59.70	56.17
Jet fuel[5]	22.49	26.21	24.79	24.54	44.75	35.92	34.59	76.97	51.27	48.75
Distillate fuel oil	26.18	32.17	30.27	29.89	52.35	42.07	40.35	86.98	58.97	55.83
Residual fuel oil	17.65	19.45	18.41	18.25	33.55	27.03	25.93	58.78	39.53	36.84
Natural gas	6.68	8.37	8.16	8.44	14.04	11.41	11.42	26.01	18.06	17.42
Metallurgical coal	7.01	10.94	10.09	9.83	17.78	13.92	13.12	27.68	18.34	16.76
Other coal	2.45	3.14	2.97	2.95	5.02	4.03	3.84	8.00	5.37	4.92
Coal to liquids	- -	- -	- -	2.37	- -	3.52	3.36	7.28	4.87	4.30
Electricity	29.03	34.59	31.71	31.41	49.24	39.20	37.96	76.55	52.12	48.63
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	248.08	295.03	280.71	286.39	441.11	374.04	387.49	707.41	527.54	552.03
Commercial	179.97	223.21	209.48	209.95	345.35	281.23	276.49	589.66	411.95	395.67
Industrial	225.18	290.58	298.68	323.30	444.67	407.07	437.25	743.64	583.76	636.70
Transportation	718.25	819.97	801.07	817.92	1,179.60	1,034.13	1,059.28	1,956.18	1,486.52	1,562.18
Total non-renewable expenditures	1,371.48	1,628.79	1,589.94	1,637.57	2,410.74	2,096.47	2,160.51	3,996.88	3,009.77	3,146.58
Transportation renewable expenditures	1.24	3.34	2.81	2.83	13.28	6.06	5.62	21.08	8.33	10.74
Total expenditures	**1,372.71**	**1,632.13**	**1,592.75**	**1,640.40**	**2,424.02**	**2,102.52**	**2,166.12**	**4,017.96**	**3,018.11**	**3,157.32**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), (2012/08) (Washington, DC, August 2012). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2011 transportation sector natural gas delivered prices are model results. 2011 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2011 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2011 coal prices based on: EIA, (2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWMACRO.D110912A, REF2013.D102312A, and HIGHMACRO.D110912A.

Table B4. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	2011	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Real gross domestic product	**13,299**	**15,717**	**16,859**	**17,754**	**18,703**	**21,355**	**23,232**	**23,283**	**27,277**	**30,552**
Components of real gross domestic product										
Real consumption	9,429	10,836	11,528	12,113	12,482	14,243	15,541	14,836	17,917	20,161
Real investment	1,744	2,530	2,909	3,335	3,363	3,914	4,504	4,776	5,409	6,269
Real government spending	2,524	2,358	2,446	2,512	2,442	2,659	2,777	2,620	2,980	3,172
Real exports	1,777	2,896	3,016	3,102	4,789	5,214	5,652	7,650	8,357	9,553
Real imports	2,185	2,817	2,927	3,163	4,089	4,311	4,806	5,847	6,518	7,531
Energy intensity (thousand Btu per 2005 dollar of GDP)										
Delivered energy	5.34	4.52	4.39	4.33	3.68	3.48	3.41	3.01	2.85	2.81
Total energy	7.35	6.17	5.99	5.90	5.12	4.81	4.70	4.20	3.95	3.91
Price indices										
GDP chain-type price index (2005=1.000)	1.134	1.408	1.307	1.275	1.991	1.564	1.469	2.847	1.871	1.678
Consumer price index (1982-4=1)										
All-urban	2.25	2.86	2.66	2.59	4.13	3.27	3.07	6.09	4.04	3.64
Energy commodities and services	2.44	2.90	2.70	2.67	4.42	3.53	3.39	7.18	4.86	4.57
Wholesale price index (1982=1.00)										
All commodities	2.01	2.39	2.22	2.21	3.31	2.59	2.48	4.73	3.10	2.88
Fuel and power	2.16	2.63	2.48	2.50	4.18	3.38	3.30	7.17	4.90	4.65
Metals and metal products	2.26	2.68	2.52	2.62	3.53	2.83	2.83	4.63	3.16	3.22
Industrial commodities excluding energy	1.93	2.30	2.12	2.11	3.02	2.34	2.22	4.01	2.57	2.37
Interest rates (percent, nominal)										
Federal funds rate	0.10	5.52	4.04	3.50	6.97	3.97	3.29	7.11	3.74	3.04
10-year treasury note	2.79	7.36	4.88	4.09	7.69	4.95	4.17	7.72	4.86	4.06
AA utility bond rate	4.78	9.84	6.91	5.57	10.47	7.21	5.77	10.90	7.39	5.53
Value of shipments (billion 2005 dollars)										
Service sectors	21,168	24,814	26,492	28,005	29,028	32,624	35,626	33,484	38,529	43,296
Total industrial	6,019	7,136	7,894	8,633	7,721	9,087	10,325	8,909	10,616	12,730
Agriculture, mining, and construction	1,582	1,937	2,211	2,535	1,986	2,375	2,775	2,239	2,644	3,099
Manufacturing	4,438	5,199	5,683	6,099	5,736	6,712	7,550	6,670	7,972	9,631
Energy-intensive	1,615	1,783	1,893	1,992	1,817	2,027	2,182	1,891	2,144	2,394
Non-energy-intensive	2,823	3,416	3,790	4,106	3,919	4,685	5,368	4,779	5,828	7,237
Total shipments	**27,187**	**31,950**	**34,385**	**36,639**	**36,749**	**41,711**	**45,951**	**42,393**	**49,145**	**56,026**
Population and employment (millions)										
Population with armed forces overseas	312.4	338.2	340.5	342.9	367.1	372.4	378.7	395.2	404.4	415.4
Population, aged 16 and over	247.0	268.0	269.5	271.3	292.3	296.3	300.9	316.0	322.9	331.0
Population, over age 65	41.6	55.0	55.4	55.5	72.1	72.7	73.0	81.1	81.8	82.6
Employment, nonfarm	131.3	146.6	149.2	153.3	156.5	160.8	165.7	167.1	174.0	182.5
Employment, manufacturing	11.7	11.8	12.4	13.0	10.4	11.2	12.2	9.3	9.9	11.3
Key labor indicators										
Labor force (millions)	153.6	163.8	164.7	166.1	172.5	174.9	178.1	186.2	190.7	196.1
Non-farm labor productivity (1992=1.00)	1.10	1.20	1.25	1.28	1.40	1.54	1.60	1.66	1.88	1.99
Unemployment rate (percent)	8.95	5.93	5.49	5.02	5.47	5.32	5.08	5.42	5.24	4.96
Key indicators for energy demand										
Real disposable personal income	10,150	12,097	12,655	13,209	14,637	15,948	17,001	17,912	19,785	21,416
Housing starts (millions)	0.66	1.38	1.89	2.59	1.25	1.89	2.74	1.25	1.89	2.89
Commercial floorspace (billion square feet)	81.7	88.5	89.1	89.7	96.3	98.1	100.0	105.4	108.8	112.3
Unit sales of light-duty vehicles (millions)	12.73	15.39	16.85	18.12	15.08	17.74	19.13	15.40	19.21	21.87

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2011: IHS Global Insight, Global Insight Industry and Employment models, August 2012. **Projections:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs LOWMACRO.D110912A, REF2013.D102312A, and HIGHMACRO.D110912A.

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Price case comparisons

Table C1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2011	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Production										
Crude oil and lease condensate	12.16	15.22	15.95	16.61	11.89	13.47	15.07	9.99	13.12	14.63
Natural gas plant liquids	2.88	3.98	4.14	4.24	3.79	3.85	3.99	3.69	3.89	4.08
Dry natural gas	23.51	26.44	27.19	27.61	28.09	30.44	31.87	30.91	33.87	36.61
Coal[1]	22.21	22.13	21.74	21.43	23.15	23.25	22.76	24.28	23.54	23.34
Nuclear / uranium[2]	8.26	9.25	9.25	9.25	9.49	9.49	9.53	9.14	9.44	10.63
Hydropower	3.17	2.83	2.83	2.83	2.86	2.87	2.88	2.91	2.92	2.92
Biomass[3]	4.05	4.85	5.00	4.95	5.27	5.42	5.48	6.57	6.96	7.66
Other renewable energy[4]	1.58	2.24	2.22	2.21	2.47	2.50	2.54	3.59	3.84	4.16
Other[5]	1.20	0.83	0.83	0.84	0.95	0.88	0.85	0.97	0.89	0.80
Total	**79.02**	**87.78**	**89.16**	**89.97**	**87.96**	**92.18**	**94.96**	**92.06**	**98.46**	**104.83**
Imports										
Crude oil	19.46	16.52	15.02	13.35	19.35	16.33	13.28	22.55	16.89	13.07
Liquid fuels and other petroleum[6]	5.24	6.24	5.55	5.02	6.31	5.33	4.31	6.73	4.82	3.75
Natural gas[7]	3.54	2.98	2.58	2.42	3.44	2.63	2.49	2.90	2.01	1.88
Other imports[8]	0.43	0.11	0.11	0.36	0.03	0.13	0.89	0.24	0.84	1.21
Total	**28.66**	**25.85**	**23.26**	**21.16**	**29.13**	**24.41**	**20.96**	**32.42**	**24.55**	**19.91**
Exports										
Liquid fuels and other petroleum[9]	6.08	5.40	5.37	5.30	5.41	5.25	5.14	5.87	5.71	5.57
Natural gas[10]	1.52	2.67	2.67	2.66	3.53	4.71	5.27	4.63	5.56	7.82
Coal	2.75	3.17	3.13	3.07	3.55	3.51	3.45	4.08	3.79	3.41
Total	**10.35**	**11.24**	**11.17**	**11.03**	**12.48**	**13.47**	**13.86**	**14.59**	**15.06**	**16.80**
Discrepancy[11]	**-0.36**	**0.24**	**0.21**	**0.22**	**0.44**	**0.30**	**0.20**	**0.58**	**0.32**	**0.21**
Consumption										
Liquid fuels and other petroleum[12]	37.02	38.62	37.54	36.21	37.84	36.08	34.04	39.34	36.07	33.77
Natural gas	24.91	26.56	26.77	27.04	27.80	27.95	28.66	28.97	29.83	30.01
Coal[13]	19.66	18.93	18.59	18.50	19.54	19.70	19.94	20.32	20.35	20.71
Nuclear / uranium[2]	8.26	9.25	9.25	9.25	9.49	9.49	9.53	9.14	9.44	10.63
Hydropower	3.17	2.83	2.83	2.83	2.86	2.87	2.88	2.91	2.92	2.92
Biomass[14]	2.74	3.42	3.53	3.53	3.90	3.94	3.99	4.74	4.91	5.21
Other renewable energy[4]	1.58	2.24	2.22	2.21	2.47	2.50	2.54	3.59	3.84	4.16
Other[15]	0.35	0.31	0.31	0.31	0.26	0.28	0.28	0.29	0.29	0.31
Total	**97.70**	**102.16**	**101.04**	**99.88**	**104.17**	**102.81**	**101.86**	**109.32**	**107.64**	**107.73**
Prices (2011 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.26	68.90	105.57	155.28	71.90	130.47	191.90	74.90	162.68	237.16
West Texas Intermediate	94.86	66.90	103.57	153.28	69.90	128.47	189.90	72.90	160.68	235.16
Natural gas at Henry Hub (dollars per million Btu)	3.98	4.08	4.13	4.33	5.15	5.40	6.03	7.06	7.83	8.96
Coal (dollars per ton) at the minemouth[16]	41.16	47.84	49.26	50.56	53.51	55.64	57.33	58.08	61.28	64.50
Coal (dollars per million Btu)										
at the minemouth[16]	2.04	2.39	2.45	2.52	2.68	2.79	2.87	2.92	3.08	3.22
Average end-use[17]	2.57	2.66	2.77	2.89	2.93	3.10	3.24	3.19	3.42	3.61
Average electricity (cents per kilowatthour)	9.9	9.3	9.4	9.5	9.5	9.7	10.0	10.3	10.8	11.3

Table C1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2011	Projections 2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.26	79.61	121.73	177.97	100.62	180.04	260.76	127.14	268.50	382.50
West Texas Intermediate	94.86	77.30	119.43	175.68	97.82	177.28	258.04	123.74	265.20	379.28
Natural gas at Henry Hub (dollars per million Btu)	3.98	4.71	4.77	4.97	7.21	7.45	8.20	11.98	12.92	14.46
Coal (dollars per ton) at the minemouth[16]	41.16	55.27	56.81	57.95	74.88	76.78	77.90	98.60	101.14	104.03
Coal (dollars per million Btu) at the minemouth[16]	2.04	2.76	2.83	2.88	3.76	3.85	3.90	4.96	5.08	5.20
Average end-use[17]	2.57	3.08	3.19	3.31	4.10	4.28	4.41	5.42	5.65	5.83
Average electricity (cents per kilowatthour)	9.9	10.7	10.8	10.9	13.3	13.4	13.6	17.5	17.8	18.3

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2011 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012). 2011 petroleum supply values: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2011 crude oil spot prices: Thomson Reuters. Other 2011 coal values: *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012). Other 2011 values: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

Table C2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2011	Projections 2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Energy consumption										
Residential										
Propane	0.53	0.53	0.52	0.52	0.53	0.52	0.51	0.54	0.52	0.51
Kerosene	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	0.59	0.54	0.51	0.48	0.44	0.40	0.37	0.37	0.32	0.30
Liquid fuels and other petroleum subtotal	1.14	1.08	1.05	1.01	0.98	0.93	0.89	0.92	0.86	0.82
Natural gas	4.83	4.64	4.62	4.61	4.48	4.46	4.42	4.27	4.23	4.17
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Renewable energy[1]	0.45	0.37	0.44	0.50	0.36	0.45	0.52	0.34	0.45	0.53
Electricity	4.86	4.87	4.84	4.81	5.41	5.36	5.31	6.13	6.03	5.93
Delivered energy	**11.28**	**10.97**	**10.95**	**10.94**	**11.23**	**11.20**	**11.15**	**11.67**	**11.57**	**11.46**
Electricity related losses	10.20	9.73	9.66	9.59	10.52	10.45	10.39	11.60	11.50	11.56
Total	**21.48**	**20.70**	**20.62**	**20.52**	**21.75**	**21.65**	**21.54**	**23.27**	**23.08**	**23.02**
Commercial										
Propane	0.14	0.16	0.16	0.15	0.18	0.16	0.16	0.19	0.17	0.16
Motor gasoline[2]	0.05	0.06	0.05	0.05	0.06	0.06	0.05	0.07	0.06	0.06
Kerosene	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.01	0.00
Distillate fuel oil	0.42	0.38	0.34	0.31	0.37	0.32	0.29	0.37	0.30	0.27
Residual fuel oil	0.07	0.12	0.09	0.08	0.12	0.09	0.07	0.13	0.09	0.07
Liquid fuels and other petroleum subtotal	0.69	0.72	0.65	0.60	0.73	0.64	0.58	0.76	0.63	0.56
Natural gas	3.23	3.41	3.40	3.38	3.52	3.50	3.46	3.72	3.68	3.60
Coal	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.50	4.73	4.72	4.70	5.26	5.22	5.18	5.79	5.72	5.64
Delivered energy	**8.60**	**9.04**	**8.95**	**8.85**	**9.69**	**9.54**	**9.39**	**10.45**	**10.21**	**9.98**
Electricity related losses	9.45	9.46	9.42	9.37	10.22	10.18	10.15	10.96	10.92	11.00
Total	**18.05**	**18.50**	**18.37**	**18.23**	**19.91**	**19.72**	**19.54**	**21.42**	**21.13**	**20.97**
Industrial[4]										
Liquefied petroleum gases	2.10	2.37	2.46	2.52	2.32	2.47	2.50	2.21	2.30	2.31
Propylene	0.40	0.58	0.56	0.52	0.56	0.52	0.49	0.50	0.46	0.46
Motor gasoline[2]	0.27	0.32	0.32	0.32	0.33	0.32	0.31	0.34	0.32	0.31
Distillate fuel oil	1.21	1.27	1.22	1.20	1.28	1.18	1.13	1.37	1.22	1.16
Residual fuel oil	0.11	0.12	0.11	0.10	0.12	0.11	0.10	0.13	0.11	0.10
Petrochemical feedstocks	0.88	1.09	1.03	1.02	1.15	1.08	1.08	1.15	1.09	1.09
Other petroleum[5]	3.61	3.79	3.54	3.37	3.79	3.46	3.29	4.11	3.65	3.42
Liquid fuels and other petroleum subtotal	8.57	9.53	9.25	9.05	9.56	9.14	8.89	9.79	9.16	8.85
Natural gas	6.92	7.79	7.86	7.90	7.94	7.97	7.90	8.04	8.08	8.01
Natural-gas-to-liquids heat and power	0.00	0.00	0.13	0.15	0.00	0.21	0.28	0.00	0.33	0.53
Lease and plant fuel[6]	1.42	1.53	1.57	1.62	1.56	1.73	2.00	1.64	1.97	2.49
Natural gas subtotal	8.34	9.32	9.56	9.67	9.50	9.91	10.18	9.68	10.38	11.03
Metallurgical coal	0.56	0.61	0.60	0.59	0.52	0.52	0.52	0.46	0.46	0.47
Other industrial coal	1.04	1.00	1.00	1.00	1.00	1.00	1.00	1.05	1.05	1.05
Coal-to-liquids heat and power	0.00	0.00	0.00	0.11	0.00	0.09	0.21	0.00	0.15	0.39
Net coal coke imports	0.01	-0.01	-0.01	-0.01	-0.04	-0.04	-0.04	-0.05	-0.05	-0.05
Coal subtotal	1.62	1.60	1.58	1.69	1.48	1.57	1.69	1.46	1.61	1.86
Biofuels heat and coproducts	0.67	0.82	0.82	0.80	0.86	0.85	0.87	1.27	1.37	1.64
Renewable energy[7]	1.51	1.73	1.72	1.70	2.03	1.97	1.91	2.39	2.28	2.20
Electricity	3.33	4.00	3.95	3.90	4.00	3.96	3.92	3.93	3.91	3.90
Delivered energy	**24.04**	**27.01**	**26.87**	**26.80**	**27.43**	**27.40**	**27.44**	**28.52**	**28.71**	**29.48**
Electricity related losses	6.99	7.99	7.89	7.78	7.78	7.72	7.66	7.44	7.45	7.60
Total	**31.03**	**35.00**	**34.76**	**34.58**	**35.21**	**35.11**	**35.11**	**35.96**	**36.16**	**37.08**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2011	Projections 2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Transportation										
Propane	0.06	0.05	0.06	0.07	0.05	0.07	0.08	0.06	0.08	0.10
E85[8]	0.05	0.06	0.08	0.11	0.13	0.16	0.34	0.15	0.17	0.61
Motor gasoline[2]	16.31	15.50	14.88	14.16	13.91	13.06	12.21	13.85	12.64	11.51
Jet fuel[9]	3.01	3.12	3.11	3.10	3.29	3.28	3.28	3.43	3.42	3.41
Distillate fuel oil[10]	5.91	7.38	7.28	6.95	7.98	7.61	6.58	9.16	7.90	6.68
Residual fuel oil	0.82	0.84	0.84	0.84	0.85	0.86	0.86	0.87	0.87	0.87
Other petroleum[11]	0.17	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16
Liquid fuels and other petroleum subtotal	26.32	27.11	26.42	25.39	26.38	25.20	23.51	27.67	25.24	23.35
Pipeline fuel natural gas	0.70	0.71	0.71	0.72	0.72	0.74	0.76	0.74	0.78	0.81
Compressed / liquefied natural gas	0.04	0.06	0.08	0.35	0.07	0.26	1.24	0.09	1.05	2.24
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.07	0.08
Delivered energy	**27.09**	**27.91**	**27.24**	**26.49**	**27.21**	**26.25**	**25.57**	**28.56**	**27.14**	**26.49**
Electricity related losses	0.05	0.06	0.06	0.06	0.08	0.09	0.10	0.10	0.13	0.16
Total	**27.13**	**27.97**	**27.30**	**26.56**	**27.29**	**26.33**	**25.67**	**28.67**	**27.27**	**26.66**
Delivered energy consumption for all sectors										
Liquefied petroleum gases	2.82	3.11	3.21	3.26	3.08	3.23	3.25	2.99	3.08	3.08
Propylene	0.40	0.58	0.56	0.52	0.56	0.52	0.49	0.50	0.46	0.46
E85[8]	0.05	0.06	0.08	0.11	0.13	0.16	0.34	0.15	0.17	0.61
Motor gasoline[2]	16.64	15.88	15.26	14.53	14.30	13.43	12.57	14.26	13.03	11.87
Jet fuel[9]	3.01	3.12	3.11	3.10	3.29	3.28	3.28	3.43	3.42	3.41
Kerosene	0.03	0.03	0.03	0.02	0.03	0.02	0.02	0.03	0.02	0.02
Distillate fuel oil	8.12	9.57	9.35	8.94	10.08	9.51	8.37	11.27	9.74	8.41
Residual fuel oil	1.01	1.08	1.05	1.02	1.10	1.05	1.03	1.12	1.07	1.05
Petrochemical feedstocks	0.88	1.09	1.03	1.02	1.15	1.08	1.08	1.15	1.09	1.09
Other petroleum[12]	3.77	3.93	3.69	3.52	3.94	3.61	3.44	4.26	3.80	3.58
Liquid fuels and other petroleum subtotal	36.72	38.44	37.37	36.04	37.66	35.90	33.86	39.15	35.88	33.59
Natural gas	15.03	15.90	15.95	16.25	16.01	16.19	17.02	16.12	17.05	18.03
Natural-gas-to-liquids heat and power	0.00	0.00	0.13	0.15	0.00	0.21	0.28	0.00	0.33	0.53
Lease and plant fuel[6]	1.42	1.53	1.57	1.62	1.56	1.73	2.00	1.64	1.97	2.49
Pipeline natural gas	0.70	0.71	0.71	0.72	0.72	0.74	0.76	0.74	0.78	0.81
Natural gas subtotal	17.15	18.14	18.36	18.73	18.29	18.87	20.06	18.50	20.13	21.86
Metallurgical coal	0.56	0.61	0.60	0.59	0.52	0.52	0.52	0.46	0.46	0.47
Other coal	1.10	1.06	1.06	1.05	1.06	1.06	1.06	1.10	1.11	1.11
Coal-to-liquids heat and power	0.00	0.00	0.00	0.11	0.00	0.09	0.21	0.00	0.15	0.39
Net coal coke imports	0.01	-0.01	-0.01	-0.01	-0.04	-0.04	-0.04	-0.05	-0.05	-0.05
Coal subtotal	1.67	1.66	1.64	1.74	1.54	1.63	1.74	1.51	1.67	1.91
Biofuels heat and coproducts	0.67	0.82	0.82	0.80	0.86	0.85	0.87	1.27	1.37	1.64
Renewable energy[13]	2.08	2.23	2.28	2.33	2.51	2.54	2.56	2.86	2.86	2.86
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.71	13.63	13.54	13.44	14.71	14.59	14.46	15.91	15.72	15.55
Delivered energy	**71.01**	**74.92**	**74.01**	**73.08**	**75.57**	**74.38**	**73.56**	**79.21**	**77.63**	**77.41**
Electricity related losses	26.69	27.24	27.03	26.80	28.60	28.43	28.30	30.11	30.00	30.32
Total	**97.70**	**102.16**	**101.04**	**99.88**	**104.17**	**102.81**	**101.86**	**109.32**	**107.64**	**107.73**
Electric power[14]										
Distillate fuel oil	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Residual fuel oil	0.23	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11
Liquid fuels and other petroleum subtotal	0.30	0.18	0.18	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Natural gas	7.76	8.42	8.40	8.31	9.52	9.08	8.60	10.47	9.70	8.16
Steam coal	17.99	17.28	16.95	16.76	18.01	18.07	18.19	18.81	18.68	18.79
Nuclear / uranium[15]	8.26	9.25	9.25	9.25	9.49	9.49	9.53	9.14	9.44	10.63
Renewable energy[16]	4.74	5.44	5.49	5.45	5.85	5.93	5.99	7.13	7.44	7.80
Electricity imports	0.13	0.08	0.08	0.08	0.04	0.05	0.05	0.06	0.06	0.08
Total[17]	**39.40**	**40.87**	**40.57**	**40.24**	**43.31**	**43.02**	**42.76**	**46.02**	**45.73**	**45.87**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2011	2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Total energy consumption										
Liquefied petroleum gases	2.82	3.11	3.21	3.26	3.08	3.23	3.25	2.99	3.08	3.08
Propylene	0.40	0.58	0.56	0.52	0.56	0.52	0.49	0.50	0.46	0.46
E85[8]	0.05	0.06	0.08	0.11	0.13	0.16	0.34	0.15	0.17	0.61
Motor gasoline[2]	16.64	15.88	15.26	14.53	14.30	13.43	12.57	14.26	13.03	11.87
Jet fuel[9]	3.01	3.12	3.11	3.10	3.29	3.28	3.28	3.43	3.42	3.41
Kerosene	0.03	0.03	0.03	0.02	0.03	0.02	0.02	0.03	0.02	0.02
Distillate fuel oil	8.18	9.65	9.43	9.01	10.15	9.59	8.45	11.34	9.82	8.49
Residual fuel oil	1.24	1.18	1.15	1.12	1.20	1.15	1.13	1.23	1.17	1.15
Petrochemical feedstocks	0.88	1.09	1.03	1.02	1.15	1.08	1.08	1.15	1.09	1.09
Other petroleum[12]	3.77	3.93	3.69	3.52	3.94	3.61	3.44	4.26	3.80	3.58
Liquid fuels and other petroleum subtotal	37.02	38.62	37.54	36.21	37.84	36.08	34.04	39.34	36.07	33.77
Natural gas	22.79	24.32	24.36	24.55	25.53	25.27	25.62	26.59	26.75	26.18
Natural-gas-to-liquids heat and power	0.00	0.00	0.13	0.15	0.00	0.21	0.28	0.00	0.33	0.53
Lease and plant fuel[6]	1.42	1.53	1.57	1.62	1.56	1.73	2.00	1.64	1.97	2.49
Pipeline natural gas	0.70	0.71	0.71	0.72	0.72	0.74	0.76	0.74	0.78	0.81
Natural gas subtotal	24.91	26.56	26.77	27.04	27.80	27.95	28.66	28.97	29.83	30.01
Metallurgical coal	0.56	0.61	0.60	0.59	0.52	0.52	0.52	0.46	0.46	0.47
Other coal	19.09	18.34	18.01	17.81	19.06	19.12	19.25	19.91	19.79	19.90
Coal-to-liquids heat and power	0.00	0.00	0.00	0.11	0.00	0.09	0.21	0.00	0.15	0.39
Net coal coke imports	0.01	-0.01	-0.01	-0.01	-0.04	-0.04	-0.04	-0.05	-0.05	-0.05
Coal subtotal	19.66	18.93	18.59	18.50	19.54	19.70	19.94	20.32	20.35	20.71
Nuclear / uranium[15]	8.26	9.25	9.25	9.25	9.49	9.49	9.53	9.14	9.44	10.63
Biofuels heat and coproducts	0.67	0.82	0.82	0.80	0.86	0.85	0.87	1.27	1.37	1.64
Renewable energy[18]	6.82	7.67	7.77	7.77	8.36	8.47	8.54	9.98	10.30	10.65
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity imports	0.13	0.08	0.08	0.08	0.04	0.05	0.05	0.06	0.06	0.08
Total	**97.70**	**102.16**	**101.04**	**99.88**	**104.17**	**102.81**	**101.86**	**109.32**	**107.64**	**107.73**
Energy use and related statistics										
Delivered energy use	71.01	74.92	74.01	73.08	75.57	74.38	73.56	79.21	77.63	77.41
Total energy use	97.70	102.16	101.04	99.88	104.17	102.81	101.86	109.32	107.64	107.73
Ethanol consumed in motor gasoline and E85	1.17	1.34	1.34	1.30	1.29	1.24	1.28	1.29	1.21	1.40
Population (millions)	312.38	340.45	340.45	340.45	372.41	372.41	372.41	404.39	404.39	404.39
Gross domestic product (billion 2005 dollars)	13,299	16,932	16,859	16,803	21,437	21,355	21,301	27,460	27,277	27,270
Carbon dioxide emissions (million metric tons)	5,471	5,559	5,455	5,365	5,636	5,523	5,432	5,887	5,691	5,548

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE-EIA-0384(2011) (Washington, DC, September 2012). 2011 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2012. 2011 carbon dioxide emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

Table C3. Energy prices by sector and source
(2010 dollars per million Btu, unless otherwise noted)

Sector and source	2011	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil Price
Residential										
Propane	25.06	21.80	23.41	24.99	22.85	25.73	27.96	23.78	27.99	30.62
Distillate fuel oil	26.38	20.03	26.91	35.67	20.57	31.26	42.37	21.07	36.54	50.06
Natural gas	10.80	11.59	11.78	12.00	13.08	13.37	13.99	15.59	16.36	17.67
Electricity	34.34	33.29	33.62	34.11	33.95	34.56	35.51	35.71	37.10	38.85
Commercial										
Propane	22.10	18.08	20.04	22.02	19.35	22.97	25.89	20.51	25.94	29.52
Distillate fuel oil	25.87	17.40	24.26	32.84	18.14	28.51	39.66	18.60	33.74	47.32
Residual fuel oil	19.17	9.76	14.82	21.95	10.44	18.77	27.34	10.95	23.41	35.80
Natural gas	8.84	9.30	9.47	9.68	10.43	10.70	11.29	12.49	13.21	14.48
Electricity	29.98	28.27	28.57	29.04	28.02	28.65	29.55	30.33	31.75	33.58
Industrial[1]										
Propane	22.54	18.40	20.51	22.64	19.74	23.64	26.78	20.90	26.78	30.64
Distillate fuel oil	26.50	17.82	24.67	33.13	18.79	28.91	40.09	19.26	34.16	47.78
Residual fuel oil	18.86	12.07	17.19	24.34	12.71	21.09	29.79	13.21	25.78	38.15
Natural gas[2]	4.89	5.44	5.53	5.70	6.43	6.56	7.12	8.30	8.88	10.01
Metallurgical coal	7.01	8.62	8.75	8.89	9.91	10.09	10.28	10.86	11.11	11.40
Other industrial coal	3.43	3.33	3.44	3.57	3.54	3.71	3.85	3.86	4.06	4.26
Coal to liquids	- -	- -	- -	2.24	- -	2.55	2.64	- -	2.95	3.16
Electricity	19.98	18.50	18.72	19.10	19.29	19.73	20.42	21.63	22.74	24.17
Transportation										
Propane	26.06	22.87	24.48	26.05	23.92	26.80	29.02	24.86	29.07	31.69
E85[3]	25.30	25.56	29.64	35.68	20.70	26.94	37.43	20.19	30.58	44.43
Motor gasoline[4]	28.70	21.86	27.84	35.94	21.67	30.73	41.08	22.12	36.18	49.07
Jet fuel[5]	22.49	14.55	21.50	29.81	15.36	26.03	36.77	16.16	31.07	44.44
Diesel fuel (distillate fuel oil)[6]	26.15	19.78	26.61	35.02	20.82	30.81	42.01	21.30	36.05	49.68
Residual fuel oil	17.83	10.00	14.91	21.28	10.59	18.34	26.44	10.98	22.45	32.70
Natural gas[7]	16.14	16.52	16.87	18.82	17.02	18.90	19.95	18.48	21.20	22.38
Electricity	32.77	29.58	29.60	29.71	31.05	31.53	32.69	33.65	35.07	37.01
Electric power[8]										
Distillate fuel oil	23.30	15.56	22.45	31.20	16.06	26.80	37.87	16.58	32.03	45.58
Residual fuel oil	15.97	19.75	24.94	32.23	20.84	29.36	38.13	21.51	34.54	46.84
Natural gas	4.77	4.79	4.90	5.07	5.86	6.05	6.55	7.79	8.38	9.34
Steam coal	2.38	2.41	2.52	2.64	2.69	2.87	3.02	2.97	3.20	3.40
Average price to all users[9]										
Propane	17.13	11.34	13.69	16.52	12.98	18.14	23.54	14.84	23.79	31.84
E85[3]	25.30	25.56	29.64	35.68	20.70	26.94	37.43	20.19	30.58	44.43
Motor gasoline[4]	28.47	21.86	27.84	35.94	21.66	30.72	41.07	22.11	36.17	49.06
Jet fuel[5]	22.49	14.55	21.50	29.81	15.36	26.03	36.77	16.16	31.07	44.44
Distillate fuel oil	26.18	19.41	26.25	34.69	20.42	30.48	41.65	20.92	35.73	49.32
Residual fuel oil	17.65	11.00	15.97	22.54	11.66	19.59	27.83	12.16	23.95	34.70
Natural gas	6.68	6.96	7.07	7.39	7.97	8.27	9.28	9.89	10.94	12.65
Metallurgical coal	7.01	8.62	8.75	8.89	9.91	10.09	10.28	10.86	11.11	11.40
Other coal	2.45	2.47	2.57	2.70	2.74	2.92	3.07	3.02	3.25	3.45
Coal to liquids	- -	- -	- -	2.24	- -	2.55	2.64	- -	2.95	3.16
Electricity	29.03	27.20	27.50	27.97	27.84	28.41	29.28	30.27	31.58	33.25
Non-renewable energy expenditures by sector (billion 2011 dollars)										
Residential	248.08	238.38	243.44	249.62	263.61	271.05	280.75	306.29	319.63	335.09
Commercial	179.97	177.66	181.68	186.64	197.00	203.80	212.25	236.19	249.60	264.69
Industrial	225.18	228.72	259.03	297.45	246.43	294.99	347.49	273.46	353.70	429.01
Transportation	718.25	544.15	694.73	877.09	533.56	749.40	956.36	574.15	900.68	1,141.45
Total non-renewable expenditures	1,371.48	1,188.91	1,378.87	1,610.80	1,240.60	1,519.24	1,796.86	1,390.08	1,823.61	2,170.24
Transportation renewable expenditures	1.24	1.50	2.44	3.87	2.75	4.39	12.79	2.94	5.05	27.17
Total expenditures	**1,372.71**	**1,190.40**	**1,381.31**	**1,614.68**	**1,243.35**	**1,523.63**	**1,809.64**	**1,393.03**	**1,828.66**	**2,197.42**

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2011	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Residential										
Propane	25.06	25.19	27.00	28.64	31.98	35.51	37.99	40.37	46.20	49.38
Distillate fuel oil	26.38	23.14	31.03	40.88	28.79	43.14	57.58	35.77	60.31	80.74
Natural gas	10.80	13.39	13.58	13.75	18.30	18.45	19.01	26.46	27.01	28.51
Electricity	34.34	38.46	38.76	39.09	47.52	47.69	48.25	60.62	61.23	62.66
Commercial										
Propane	22.10	20.89	23.11	25.24	27.08	31.70	35.18	34.81	42.82	47.62
Distillate fuel oil	25.87	20.10	27.97	37.64	25.39	39.34	53.88	31.58	55.68	76.33
Residual fuel oil	19.17	11.28	17.09	25.16	14.61	25.90	37.15	18.59	38.64	57.74
Natural gas	8.84	10.74	10.92	11.09	14.59	14.76	15.34	21.19	21.81	23.36
Electricity	29.98	32.66	32.94	33.29	39.21	39.54	40.15	51.48	52.40	54.16
Industrial[1]										
Propane	22.54	21.26	23.65	25.95	27.62	32.62	36.39	35.48	44.20	49.42
Distillate fuel oil	26.50	20.59	28.45	37.97	26.30	39.89	54.47	32.69	56.39	77.06
Residual fuel oil	18.86	13.95	19.82	27.90	17.78	29.10	40.48	22.42	42.55	61.53
Natural gas[2]	4.89	6.29	6.38	6.53	9.00	9.05	9.68	14.10	14.66	16.15
Metallurgical coal	7.01	9.96	10.09	10.19	13.87	13.92	13.97	18.43	18.34	18.39
Other industrial coal	3.43	3.85	3.97	4.09	4.96	5.12	5.23	6.56	6.70	6.87
Coal to liquids	- -	- -	- -	2.57	- -	3.52	3.59	- -	4.87	5.10
Electricity	19.98	21.38	21.59	21.89	26.99	27.22	27.75	36.72	37.54	38.98
Transportation										
Propane	26.06	26.42	28.22	29.86	33.48	36.98	39.43	42.20	47.97	51.11
E85[3]	25.30	29.53	34.18	40.89	28.97	37.18	50.86	34.27	50.46	71.65
Motor gasoline[4]	28.70	25.26	32.10	41.20	30.32	42.41	55.82	37.54	59.72	79.15
Jet fuel[5]	22.49	16.81	24.79	34.16	21.49	35.92	49.96	27.44	51.27	71.68
Diesel fuel (distillate fuel oil)[6]	26.15	22.85	30.68	40.14	29.14	42.52	57.08	36.15	59.50	80.13
Residual fuel oil	17.83	11.56	17.19	24.38	14.82	25.31	35.93	18.63	37.06	52.75
Natural gas[7]	16.14	19.08	19.46	21.57	23.81	26.08	27.11	31.37	34.98	36.09
Electricity	32.77	34.17	34.13	34.06	43.46	43.51	44.42	57.12	57.88	59.70
Electric power[8]										
Distillate fuel oil	23.30	17.98	25.89	35.76	22.48	36.98	51.45	28.15	52.87	73.52
Residual fuel oil	15.97	22.82	28.76	36.94	29.17	40.52	51.81	36.52	57.01	75.54
Natural gas	4.77	5.53	5.65	5.81	8.20	8.35	8.90	13.22	13.83	15.06
Steam coal	2.38	2.79	2.90	3.03	3.76	3.96	4.10	5.04	5.28	5.48

Table C3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2011	2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Average price to all users[9]										
Propane	17.13	13.10	15.78	18.93	18.16	25.03	31.99	25.19	39.26	51.36
E85[3]	25.30	29.53	34.18	40.89	28.97	37.18	50.86	34.27	50.46	71.65
Motor gasoline[4]	28.47	25.25	32.10	41.19	30.32	42.40	55.81	37.53	59.70	79.13
Jet fuel[5]	22.49	16.81	24.79	34.16	21.49	35.92	49.96	27.44	51.27	71.68
Distillate fuel oil	26.18	22.42	30.27	39.76	28.58	42.07	56.59	35.52	58.97	79.55
Residual fuel oil	17.65	12.71	18.41	25.83	16.32	27.03	37.81	20.63	39.53	55.97
Natural gas	6.68	8.04	8.16	8.47	11.15	11.41	12.61	16.79	18.06	20.40
Metallurgical coal	7.01	9.96	10.09	10.19	13.87	13.92	13.97	18.43	18.34	18.39
Other coal	2.45	2.86	2.97	3.10	3.83	4.03	4.17	5.13	5.37	5.57
Coal to liquids	- -	- -	- -	2.57	- -	3.52	3.59	- -	4.87	5.10
Electricity	29.03	31.42	31.71	32.05	38.95	39.20	39.78	51.37	52.12	53.63
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	248.08	275.42	280.71	286.10	368.92	374.04	381.49	519.90	527.54	540.45
Commercial	179.97	205.26	209.48	213.91	275.70	281.23	288.41	400.92	411.95	426.92
Industrial	225.18	264.27	298.68	340.93	344.87	407.07	472.18	464.18	583.76	691.95
Transportation	718.25	628.70	801.07	1,005.28	746.71	1,034.13	1,299.52	974.58	1,486.52	1,841.03
Total non-renewable expenditures	1,371.48	1,373.65	1,589.94	1,846.23	1,736.20	2,096.47	2,441.59	2,359.59	3,009.77	3,500.35
Transportation renewable expenditures	1.24	1.73	2.81	4.44	3.85	6.06	17.38	5.00	8.33	43.83
Total expenditures	**1,372.71**	**1,375.38**	**1,592.75**	**1,850.67**	**1,740.04**	**2,102.52**	**2,458.97**	**2,364.59**	**3,018.11**	**3,544.17**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2011 transportation sector natural gas delivered prices are model results. 2011 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2011 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2011 coal prices based on: EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

Table C4. Liquid fuels supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	2011	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil										
Domestic crude production[1]	5.67	7.12	7.47	7.78	5.57	6.30	7.04	4.67	6.13	6.82
Alaska	0.57	0.49	0.49	0.52	0.25	0.38	0.54	0.00	0.41	0.40
Lower 48 states	5.10	6.64	6.98	7.26	5.32	5.92	6.50	4.67	5.72	6.42
Net imports	8.89	7.48	6.82	6.05	8.70	7.36	5.98	10.13	7.57	5.86
Gross imports	8.94	7.48	6.82	6.05	8.70	7.36	5.98	10.13	7.57	5.86
Exports	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other crude supply[2]	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**14.81**	**14.61**	**14.29**	**13.82**	**14.27**	**13.66**	**13.02**	**14.79**	**13.70**	**12.68**
Other petroleum supply	**3.02**	**4.28**	**4.04**	**3.84**	**4.18**	**3.82**	**3.37**	**4.08**	**3.29**	**2.80**
Natural gas plant liquids	2.22	3.01	3.13	3.20	2.86	2.90	3.01	2.77	2.92	3.06
Net product imports	-0.30	0.18	-0.13	-0.35	0.26	-0.08	-0.57	0.20	-0.67	-1.15
Gross refined product imports[3]	1.15	1.62	1.47	1.41	1.73	1.53	1.24	1.99	1.42	1.07
Unfinished oil imports	0.69	0.64	0.56	0.47	0.63	0.51	0.40	0.60	0.45	0.30
Blending component imports	0.72	0.71	0.63	0.56	0.63	0.54	0.44	0.59	0.40	0.36
Exports	2.86	2.78	2.79	2.79	2.73	2.67	2.64	2.98	2.94	2.89
Refinery processing gain[4]	1.08	1.09	1.04	0.99	1.06	1.00	0.93	1.12	1.03	0.89
Product stock withdrawal	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**1.09**	**1.42**	**1.51**	**1.54**	**1.42**	**1.58**	**1.70**	**1.65**	**1.97**	**2.42**
Supply from renewable sources	0.90	1.18	1.18	1.15	1.17	1.14	1.18	1.38	1.43	1.70
Ethanol	0.84	1.08	1.08	1.04	1.04	0.99	1.03	1.04	0.97	1.12
Domestic production	0.91	1.01	1.01	0.97	0.98	0.95	0.94	0.98	0.89	1.00
Net imports	-0.07	0.07	0.07	0.07	0.05	0.04	0.09	0.06	0.08	0.12
Biodiesel	0.06	0.07	0.08	0.08	0.02	0.08	0.08	0.02	0.08	0.09
Domestic production	0.06	0.06	0.07	0.07	0.00	0.07	0.07	0.00	0.07	0.07
Net imports	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other biomass-derived liquids[5]	0.00	0.03	0.02	0.02	0.11	0.06	0.07	0.33	0.38	0.49
Liquids from gas	0.00	0.00	0.08	0.09	0.00	0.13	0.17	0.00	0.20	0.31
Liquids from coal	0.00	0.00	0.00	0.05	0.00	0.04	0.09	0.00	0.06	0.16
Other[6]	0.18	0.24	0.25	0.26	0.25	0.28	0.26	0.26	0.28	0.24
Total primary supply[7]	**18.92**	**20.31**	**19.84**	**19.21**	**19.87**	**19.06**	**18.10**	**20.52**	**18.96**	**17.90**
Liquid fuels consumption										
by fuel										
Liquefied petroleum gases	2.30	2.84	2.90	2.91	2.81	2.90	2.90	2.69	2.75	2.76
E85[8]	0.03	0.04	0.06	0.07	0.09	0.11	0.23	0.10	0.11	0.42
Motor gasoline[9]	8.74	8.67	8.34	7.94	7.81	7.34	6.87	7.79	7.12	6.49
Jet fuel[10]	1.43	1.52	1.52	1.51	1.60	1.60	1.59	1.67	1.66	1.66
Distillate fuel oil[11]	3.90	4.59	4.48	4.29	4.83	4.56	4.02	5.40	4.67	4.04
Diesel	3.51	4.12	4.04	3.87	4.41	4.18	3.66	5.00	4.33	3.71
Residual fuel oil	0.46	0.51	0.50	0.49	0.52	0.50	0.49	0.54	0.51	0.50
Other[12]	2.08	2.18	2.04	1.96	2.21	2.03	1.95	2.34	2.11	2.02
by sector										
Residential and commercial	1.06	1.06	1.01	0.96	1.02	0.95	0.90	1.01	0.91	0.86
Industrial[13]	4.43	5.21	5.10	5.02	5.22	5.05	4.95	5.25	5.00	4.87
Transportation	13.63	14.00	13.65	13.11	13.57	12.95	12.13	14.18	12.95	12.07
Electric power[14]	0.13	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Total	**18.95**	**20.35**	**19.84**	**19.17**	**19.89**	**19.04**	**18.06**	**20.53**	**18.95**	**17.89**
Discrepancy[15]	**-0.03**	**-0.04**	**0.01**	**0.03**	**-0.02**	**0.02**	**0.03**	**-0.01**	**0.01**	**0.01**

Table C4. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2011	Projections 2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Domestic refinery distillation capacity[16]	17.7	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Capacity utilization rate (percent)[17]	86.0	92.7	90.7	87.7	90.6	86.7	82.7	93.9	86.9	80.5
Net import share of product supplied (percent)	45.0	38.2	34.1	30.1	45.4	38.5	30.5	50.6	36.9	27.1
Net expenditures for imported crude oil and petroleum products (billion 2011 dollars)	362.66	184.56	259.66	336.24	220.72	342.67	410.95	265.20	433.65	495.87

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]End-of-year operable capacity.
[17]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). Other 2011 data: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

Table C5. Petroleum product prices
(2010 dollars per gallon, unless otherwise noted)

Sector and fuel	2011	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2011 dollars per barrel)										
Brent spot	111.26	68.90	105.57	155.28	71.90	130.47	191.90	74.90	162.68	237.16
West Texas Intermediate spot	94.86	66.90	103.57	153.28	69.90	128.47	189.90	72.90	160.68	235.16
Average imported refiners acquisition cost[1]	102.65	66.28	102.19	149.31	68.39	125.64	184.97	70.93	154.96	228.39
Delivered sector product prices										
Residential										
Propane	2.13	1.85	1.98	2.11	1.93	2.17	2.35	2.01	2.35	2.56
Distillate fuel oil	3.66	2.78	3.73	4.95	2.85	4.34	5.88	2.92	5.07	6.94
Commercial										
Distillate fuel oil	3.57	2.40	3.34	4.53	2.50	3.93	5.47	2.56	4.65	6.52
Residual fuel oil	2.87	1.46	2.22	3.29	1.56	2.81	4.09	1.64	3.50	5.36
Residual fuel oil (2011 dollars per barrel)	120.49	61.38	93.20	138.00	65.63	117.99	171.88	68.87	147.19	225.06
Industrial[2]										
Propane	1.92	1.56	1.74	1.92	1.67	1.99	2.25	1.76	2.25	2.56
Distillate fuel oil	3.64	2.45	3.39	4.55	2.58	3.97	5.50	2.64	4.69	6.56
Residual fuel oil	2.82	1.81	2.57	3.64	1.90	3.16	4.46	1.98	3.86	5.71
Residual fuel oil (2011 dollars per barrel)	118.58	75.90	108.07	153.04	79.88	132.58	187.31	83.04	162.10	239.83
Transportation										
Propane	2.22	1.94	2.07	2.20	2.02	2.26	2.44	2.10	2.44	2.65
Ethanol (E85)[3]	2.42	2.44	2.83	3.41	1.98	2.57	3.57	1.93	2.92	4.24
Ethanol wholesale price	2.54	2.79	3.00	3.11	2.39	2.28	2.78	2.33	2.48	3.25
Motor gasoline[4]	3.45	2.61	3.32	4.29	2.59	3.67	4.90	2.64	4.32	5.86
Jet fuel[5]	3.04	1.96	2.90	4.02	2.07	3.51	4.96	2.18	4.19	6.00
Diesel fuel (distillate fuel oil)[6]	3.58	2.71	3.65	4.80	2.85	4.22	5.76	2.92	4.94	6.81
Residual fuel oil	2.67	1.50	2.23	3.18	1.58	2.75	3.96	1.64	3.36	4.90
Residual fuel oil (2011 dollars per barrel)	112.11	62.89	93.74	133.76	66.56	115.30	166.23	69.01	141.16	205.61
Electric power[7]										
Distillate fuel oil	3.23	2.16	3.11	4.33	2.23	3.72	5.25	2.30	4.44	6.32
Residual fuel oil	2.39	2.96	3.73	4.82	3.12	4.39	5.71	3.22	5.17	7.01
Residual fuel oil (2011 dollars per barrel)	100.43	124.18	156.82	202.60	131.04	184.59	239.73	135.26	217.18	294.46
Refined petroleum product prices[8]										
Propane	1.46	0.96	1.16	1.40	1.10	1.53	1.98	1.25	2.00	2.66
Motor gasoline[4]	3.42	2.61	3.32	4.29	2.59	3.67	4.90	2.64	4.32	5.86
Jet fuel[5]	3.04	1.96	2.90	4.02	2.07	3.51	4.96	2.18	4.19	6.00
Distillate fuel oil	3.59	2.66	3.60	4.76	2.80	4.18	5.71	2.87	4.90	6.77
Residual fuel oil	2.64	1.65	2.39	3.37	1.75	2.93	4.17	1.82	3.59	5.19
Residual fuel oil (2011 dollars per barrel)	110.98	69.15	100.39	141.70	73.32	123.16	174.94	76.42	150.58	218.18
Average	**3.11**	**2.30**	**3.01**	**3.91**	**2.35**	**3.43**	**4.61**	**2.44**	**4.10**	**5.58**

Table C5. Petroleum product prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2011	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (nominal dollars per barrel)										
Brent spot	111.26	79.61	121.73	177.97	100.62	180.04	260.76	127.14	268.50	382.50
West Texas Intermediate spot	94.86	77.30	119.43	175.68	97.82	177.28	258.04	123.74	265.20	379.28
Average imported refiners acquisition cost[1]	102.65	76.57	117.84	171.13	95.72	173.38	251.33	120.40	255.76	368.36
Delivered sector product prices										
Residential										
Propane	2.13	2.14	2.29	2.42	2.70	2.99	3.19	3.41	3.88	4.13
Distillate fuel oil	3.66	3.21	4.30	5.67	3.99	5.98	7.99	4.96	8.37	11.20
Commercial										
Distillate fuel oil	3.57	2.77	3.86	5.19	3.50	5.42	7.43	4.35	7.68	10.52
Residual fuel oil	2.87	1.69	2.56	3.77	2.19	3.88	5.56	2.78	5.78	8.64
Industrial[2]										
Propane	1.92	1.80	2.00	2.20	2.33	2.75	3.06	2.99	3.71	4.14
Distillate fuel oil	3.64	2.83	3.91	5.21	3.61	5.48	7.48	4.49	7.74	10.58
Residual fuel oil	2.82	2.09	2.97	4.18	2.66	4.36	6.06	3.36	6.37	9.21
Transportation										
Propane	2.22	2.24	2.39	2.53	2.83	3.12	3.31	3.56	4.03	4.28
Ethanol (E85)[3]	2.42	2.82	3.26	3.90	2.77	3.55	4.85	3.27	4.82	6.84
Ethanol wholesale price	2.54	3.22	3.46	3.57	3.35	3.14	3.77	3.96	4.09	5.24
Motor gasoline[4]	3.45	3.02	3.83	4.92	3.62	5.06	6.66	4.48	7.13	9.45
Jet fuel[5]	3.04	2.27	3.35	4.61	2.90	4.85	6.74	3.70	6.92	9.68
Diesel fuel (distillate fuel oil)[6]	3.58	3.13	4.20	5.50	3.99	5.83	7.82	4.95	8.15	10.98
Residual fuel oil	2.67	1.73	2.57	3.65	2.22	3.79	5.38	2.79	5.55	7.90
Electric power[7]										
Distillate fuel oil	3.23	2.49	3.59	4.96	3.12	5.13	7.14	3.90	7.33	10.20
Residual fuel oil	2.39	3.42	4.31	5.53	4.37	6.06	7.76	5.47	8.53	11.31
Refined petroleum product prices[8]										
Propane	1.46	1.11	1.34	1.60	1.53	2.11	2.69	2.13	3.30	4.30
Motor gasoline[4]	3.42	3.02	3.83	4.92	3.62	5.06	6.66	4.48	7.13	9.45
Jet fuel[5]	3.04	2.27	3.35	4.61	2.90	4.85	6.74	3.70	6.92	9.68
Distillate fuel oil	3.59	3.08	4.15	5.46	3.92	5.77	7.76	4.87	8.09	10.91
Residual fuel oil (nominal dollars per barrel)	110.98	79.90	115.76	162.41	102.62	169.95	237.72	129.72	248.53	351.90
Average	**3.11**	**2.66**	**3.47**	**4.49**	**3.28**	**4.74**	**6.26**	**4.14**	**6.76**	**9.00**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2011 crude oil spot prices: Thomson Reuters. 2011 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2011 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2011 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

Table C6. International liquids supply and disposition summary
(million barrels per day, unless otherwise noted)

Supply and disposition	2011	Projections 2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Crude oil spot prices										
(2011 dollars per barrel)										
Brent	111.26	68.90	105.57	155.28	71.90	130.47	191.90	74.90	162.68	237.16
West Texas Intermediate	94.86	66.90	103.57	153.28	69.90	128.47	189.90	72.90	160.68	235.16
(nominal dollars per barrel)										
Brent	111.26	79.61	121.73	177.97	100.62	180.04	260.76	127.14	268.50	382.50
West Texas Intermediate	94.86	77.30	119.43	175.68	97.82	177.28	258.04	123.74	265.20	379.28
Liquids consumption[1]										
OECD										
United States (50 states)	18.68	20.00	19.49	18.84	19.55	18.72	17.73	20.20	18.64	17.53
United States territories	0.28	0.37	0.32	0.29	0.43	0.36	0.32	0.47	0.37	0.33
Canada	2.29	2.35	2.21	2.11	2.37	2.18	2.14	2.48	2.30	2.39
Mexico and Chile	2.41	2.81	2.66	2.57	3.30	3.05	3.01	3.82	3.47	3.51
OECD Europe[2]	14.28	14.59	13.81	13.19	15.21	13.96	13.31	15.99	14.21	13.54
Japan	4.46	4.75	4.41	4.15	4.73	4.25	3.96	4.54	3.94	3.64
South Korea	2.32	2.75	2.56	2.41	3.01	2.66	2.53	3.26	2.74	2.66
Australia and New Zealand	1.12	1.23	1.19	1.13	1.30	1.22	1.16	1.46	1.30	1.23
Total OECD	**45.83**	**48.85**	**46.63**	**44.69**	**49.90**	**46.40**	**44.15**	**52.21**	**46.96**	**44.82**
Non-OECD										
Russia	3.13	3.77	3.53	3.37	4.12	3.83	3.67	4.25	3.95	3.86
Other Europe and Eurasia[3]	2.27	2.54	2.38	2.31	2.90	2.63	2.56	3.45	3.07	3.02
China	9.85	13.00	13.29	13.23	13.79	15.58	17.21	13.83	17.59	22.13
India	3.28	4.30	4.27	4.24	5.27	5.61	6.33	5.75	6.81	9.40
Other Asia[4]	6.87	8.00	7.88	7.65	9.09	9.30	9.35	10.20	11.25	11.72
Middle East	7.51	8.56	8.40	8.16	8.81	8.92	9.03	9.07	9.78	10.57
Africa	3.31	3.78	3.63	3.47	4.10	4.05	3.96	4.29	4.49	4.43
Brazil	2.59	3.15	3.01	2.83	3.34	3.37	3.34	3.54	4.00	4.27
Other Central and South America	3.37	3.73	3.42	3.44	4.09	3.71	3.73	4.45	4.02	4.09
Total non-OECD	**42.18**	**50.82**	**49.82**	**48.69**	**55.51**	**57.00**	**59.16**	**58.84**	**64.97**	**73.49**
Total liquids consumption	**88.01**	**99.67**	**96.45**	**93.38**	**105.41**	**103.41**	**103.31**	**111.05**	**111.93**	**118.31**
Liquids production										
OPEC[5]										
Middle East	25.40	30.13	26.65	24.08	33.47	29.88	28.47	39.68	35.09	34.24
North Africa	2.39	3.65	3.27	3.00	3.75	3.48	3.33	4.22	3.96	3.87
West Africa	4.31	5.73	5.33	4.80	6.28	5.61	5.33	6.78	5.89	5.70
South America	2.99	3.41	3.09	3.03	3.44	3.01	3.05	3.80	3.20	3.27
Total OPEC	**35.08**	**42.92**	**38.34**	**34.90**	**46.94**	**41.98**	**40.17**	**54.49**	**48.13**	**47.08**
Non-OPEC										
OECD										
United States (50 states)	10.11	12.23	12.74	13.11	10.53	11.42	12.28	9.81	11.67	12.74
Canada	3.66	5.20	5.09	6.01	6.15	5.91	7.25	5.73	6.14	7.78
Mexico and Chile	2.99	1.93	1.96	1.92	1.69	1.98	1.96	1.58	2.12	2.15
OECD Europe[2]	4.19	3.38	3.38	3.28	2.90	2.84	2.76	3.51	3.36	3.56
Japan	0.18	0.18	0.17	0.17	0.19	0.18	0.19	0.20	0.19	0.20
Australia and New Zealand	0.58	0.54	0.54	0.53	0.56	0.56	0.55	0.79	0.87	0.90
Total OECD	**21.71**	**23.46**	**23.88**	**25.02**	**22.03**	**22.90**	**24.99**	**21.62**	**24.35**	**27.33**
Non-OECD										
Russia	10.23	10.29	10.75	10.80	10.76	11.43	11.45	10.53	11.48	11.88
Other Europe and Eurasia[3]	3.26	4.15	4.20	4.00	4.17	4.85	4.58	3.33	5.24	5.27
China	4.34	4.56	4.59	4.58	5.43	5.50	5.82	5.24	5.42	8.36
Other Asia[4]	3.74	3.52	3.55	3.46	3.09	3.09	3.02	2.89	2.87	2.96
Middle East	1.43	1.21	1.23	1.19	1.08	1.09	1.05	0.89	0.89	0.89
Africa	2.68	3.02	3.08	3.00	3.03	3.10	3.01	3.11	3.18	3.24
Brazil	2.53	4.52	4.35	4.51	6.72	6.96	7.14	6.53	7.61	8.82
Other Central and South America	2.17	2.38	2.40	2.32	2.42	2.46	2.38	2.65	2.69	2.82
Total non-OECD	**30.39**	**33.65**	**34.15**	**33.87**	**36.69**	**38.47**	**38.46**	**35.17**	**39.37**	**44.24**
Total liquids production	**87.18**	**100.03**	**96.38**	**93.79**	**105.65**	**103.35**	**103.62**	**111.29**	**111.85**	**118.65**
OPEC liquids market share (percent)	40.2	42.9	39.8	37.2	44.4	40.6	38.8	49.0	43.0	39.7

Table C6. International liquids supply and disposition summary (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2011	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Selected world liquids production subtotals:										
Petroleum[6]										
Crude oil and equivalents[7]	74.08	84.06	80.28	77.15	87.05	85.26	84.30	90.27	90.90	94.50
Tight oil	1.27	3.53	3.83	3.99	4.39	4.91	5.34	4.73	6.10	7.97
Bitumen[8]	1.74	3.18	3.00	3.87	4.29	3.95	5.19	3.99	4.26	5.71
Natural gas plant liquids	8.66	10.46	10.88	10.96	11.24	11.75	11.88	12.07	12.88	13.04
Refinery processing gain[9]	2.28	2.35	2.20	2.14	2.64	2.50	2.43	2.94	2.82	2.72
Liquids from renewable sources[10]	1.33	2.31	2.08	2.38	3.51	2.49	3.14	4.69	2.93	4.99
Liquids from coal[11]	0.18	0.36	0.40	0.58	0.76	0.95	1.24	0.86	1.19	2.62
Liquids from natural gas[12]	0.12	0.30	0.39	0.37	0.32	0.48	0.49	0.31	0.55	0.65
Liquids from kerogen[13]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Petroleum production[6]										
OPEC[5]										
Middle East	25.34	29.93	26.44	23.89	33.24	29.64	28.25	39.45	34.84	34.01
North Africa	2.39	3.65	3.27	3.00	3.75	3.48	3.33	4.22	3.96	3.87
West Africa	4.31	5.70	5.30	4.77	6.25	5.58	5.30	6.75	5.86	5.67
South America	2.99	3.41	3.09	3.03	3.44	3.01	3.05	3.80	3.20	3.27
Total OPEC	**35.03**	**42.69**	**38.10**	**34.70**	**46.68**	**41.71**	**39.93**	**54.24**	**47.86**	**46.83**
Non-OPEC										
OECD										
United States (50 states)	9.25	11.22	11.64	11.96	9.49	10.21	10.98	8.55	10.08	10.78
Canada	3.64	5.17	5.07	5.98	6.09	5.87	7.20	5.65	6.10	7.70
Mexico and Chile	2.99	1.93	1.96	1.92	1.69	1.98	1.96	1.58	2.12	2.15
OECD Europe[2]	3.98	3.16	3.16	3.05	2.60	2.60	2.50	3.09	3.09	3.13
Japan	0.17	0.17	0.16	0.16	0.18	0.18	0.18	0.18	0.18	0.18
Australia and New Zealand	0.57	0.53	0.53	0.52	0.54	0.55	0.54	0.77	0.86	0.89
Total OECD	**20.60**	**22.18**	**22.52**	**23.60**	**20.60**	**21.39**	**23.36**	**19.83**	**22.43**	**24.82**
Non-OECD										
Russia	10.23	10.29	10.75	10.80	10.76	11.42	11.45	10.53	11.47	11.88
Other Europe and Eurasia[3]	3.25	4.14	4.19	3.99	4.16	4.84	4.58	3.32	5.23	5.26
China	4.30	4.41	4.44	4.30	4.73	4.83	4.86	4.33	4.52	5.96
Other Asia[4]	3.67	3.40	3.42	3.32	2.87	2.88	2.79	2.65	2.65	2.67
Middle East	1.43	1.21	1.23	1.19	1.08	1.09	1.05	0.89	0.89	0.89
Africa	2.47	2.72	2.75	2.66	2.72	2.74	2.64	2.80	2.82	2.83
Brazil	2.25	3.52	3.57	3.44	5.03	5.92	5.68	4.20	6.48	6.44
Other Central and South America	2.09	2.30	2.33	2.24	2.31	2.38	2.29	2.50	2.60	2.66
Total non-OECD	**29.69**	**32.00**	**32.69**	**31.95**	**33.65**	**36.11**	**35.32**	**31.21**	**36.66**	**38.60**
Total petroleum production	**85.31**	**96.87**	**93.32**	**90.24**	**100.93**	**99.20**	**98.61**	**105.28**	**106.96**	**110.25**
OPEC petroleum market share (percent)	41.1	44.1	40.8	38.4	46.2	42.0	40.5	51.5	44.7	42.5

[1]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes production of crude oil (including lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands)), natural gas plant liquids, refinery gains, and other hydrogen and hydrocarbons for refinery feedstocks.
[7]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[8]Includes diluted and upgraded/synthetic bitumen (syncrude).
[9]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[10]Includes liquids produced from energy crops.
[11]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[12]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[13]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil).
Note: Ethanol is represented in motor gasoline equivalent barrels. Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 crude oil spot prices: Thomson Reuters. **2011 quantities and projections:** Energy Information Administration (EIA), AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A and EIA, Generate World Oil Balance Model.

Table D1. Key results for demand sector technology cases

Consumption, emissions, combined heat and power capacity and generation	2011	2020				2030			
		2012 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2012 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
Energy consumption (quadrillion Btu)									
Residential									
Liquid fuels and other petroleum[1]	1.14	1.07	1.05	1.02	0.99	0.98	0.93	0.88	0.84
Natural gas	4.83	4.73	4.62	4.36	4.03	4.70	4.46	4.00	3.48
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00
Renewable energy[2]	0.45	0.46	0.44	0.42	0.40	0.50	0.45	0.41	0.37
Electricity	4.86	4.92	4.84	4.44	3.95	5.54	5.36	4.75	4.02
Total residential	**11.28**	**11.18**	**10.95**	**10.25**	**9.38**	**11.72**	**11.20**	**10.04**	**8.72**
Nonmarketed renewables, residential	0.04	0.18	0.20	0.20	0.23	0.19	0.22	0.27	0.38
Commercial									
Liquid fuels and other petroleum[3]	0.69	0.65	0.65	0.66	0.66	0.64	0.64	0.64	0.64
Natural gas	3.23	3.37	3.40	3.37	3.39	3.46	3.50	3.46	3.50
Coal	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[4]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.50	4.86	4.72	4.36	4.11	5.52	5.22	4.44	4.11
Total commercial	**8.60**	**9.06**	**8.95**	**8.56**	**8.34**	**9.80**	**9.54**	**8.71**	**8.42**
Nonmarketed renewables, commercial	0.11	0.20	0.20	0.23	0.23	0.22	0.24	0.32	0.33
Industrial[5]									
Liquefied petroleum gases	2.10	2.46	2.46	2.47	2.51	2.48	2.47	2.49	2.57
Propylene	0.40	0.54	0.56	0.58	0.59	0.50	0.52	0.54	0.55
Distillate fuel oil	1.21	1.38	1.22	1.16	1.21	1.49	1.18	1.07	1.16
Petrochemical feedstocks	0.88	1.04	1.03	1.02	1.01	1.11	1.08	1.06	1.06
Other petroleum[6]	4.00	4.14	3.97	3.84	3.92	4.20	3.89	3.69	3.87
Liquid fuels and other petroleum	8.57	9.57	9.25	9.06	9.23	9.78	9.14	8.85	9.21
Natural gas	8.34	9.89	9.56	9.61	9.60	10.74	9.91	9.93	9.95
Coal	1.62	1.65	1.58	1.56	1.59	1.64	1.57	1.55	1.60
Renewable energy[7]	2.18	2.50	2.53	2.56	2.54	2.74	2.82	2.94	2.84
Electricity	3.33	4.09	3.95	3.86	3.97	4.33	3.96	3.82	4.07
Total industrial	**24.04**	**27.71**	**26.87**	**26.66**	**26.93**	**29.23**	**27.40**	**27.08**	**27.66**
Transportation									
E85[8]	0.05	0.08	0.08	0.08	0.09	0.16	0.16	0.16	0.16
Motor gasoline[9]	16.31	14.87	14.88	14.79	14.85	13.04	13.06	13.04	13.08
Jet fuel	3.01	3.11	3.11	3.10	3.11	3.28	3.28	3.24	3.28
Distillate fuel oil	5.91	7.29	7.28	7.04	7.22	7.65	7.61	7.23	7.50
Other petroleum[10]	1.05	1.06	1.06	1.06	1.06	1.08	1.08	1.07	1.08
Liquid fuels and other petroleum	26.32	26.41	26.42	26.07	26.34	25.22	25.20	24.74	25.11
Pipeline fuel natural gas	0.70	0.73	0.71	0.69	0.69	0.78	0.74	0.70	0.69
Compressed / liquefied natural gas	0.04	0.07	0.08	0.07	0.08	0.22	0.26	0.21	0.35
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.05
Total transportation	**27.09**	**27.25**	**27.24**	**26.87**	**27.13**	**26.27**	**26.25**	**25.70**	**26.19**
Electric power[11]									
Distillate and residual fuel oil	0.30	0.18	0.18	0.16	0.15	0.19	0.18	0.16	0.15
Natural gas	7.76	8.60	8.40	7.97	7.97	9.91	9.08	7.58	7.41
Steam coal	17.99	17.74	16.95	15.13	13.28	18.89	18.07	16.01	13.99
Nuclear / uranium[12]	8.26	9.25	9.25	9.16	9.11	9.54	9.49	9.41	9.36
Renewable energy[13]	4.74	5.58	5.49	5.27	5.12	6.46	5.93	5.57	5.31
Net electricity imports	0.13	0.09	0.08	0.08	0.08	0.05	0.05	0.03	0.03
Total electric power[14]	**39.40**	**41.67**	**40.57**	**37.99**	**35.93**	**45.27**	**43.02**	**38.99**	**36.47**
Total energy consumption									
Liquid fuels and other petroleum	37.02	37.88	37.54	36.97	37.37	36.80	36.08	35.28	35.94
Natural gas	24.91	27.39	26.77	26.07	25.74	29.82	27.95	25.87	25.37
Steam coal	19.66	19.46	18.59	16.75	14.92	20.58	19.70	17.61	15.65
Nuclear / uranium[12]	8.26	9.25	9.25	9.16	9.11	9.54	9.49	9.41	9.36
Renewable energy[15]	7.49	8.67	8.58	8.38	8.18	9.82	9.31	9.05	8.64
Other[16]	0.35	0.31	0.31	0.31	0.31	0.28	0.28	0.26	0.26
Total energy consumption	**97.70**	**102.96**	**101.04**	**97.63**	**95.64**	**106.85**	**102.81**	**97.46**	**95.22**

2040				Annual Growth 2011-2040 (percent)			
2012 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2012 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
0.93	0.86	0.80	0.75	-0.7%	-1.0%	-1.2%	-1.4%
4.61	4.23	3.70	3.12	-0.2%	-0.5%	-0.9%	-1.5%
0.01	0.00	0.00	0.00	-0.3%	-0.9%	-1.3%	-1.6%
0.53	0.45	0.40	0.34	0.6%	0.1%	-0.4%	-0.9%
6.27	6.03	5.34	4.39	0.9%	0.7%	0.3%	-0.3%
12.35	**11.57**	**10.24**	**8.61**	**0.3%**	**0.1%**	**-0.3%**	**-0.9%**
0.20	0.27	0.41	0.70	5.9%	6.9%	8.5%	10.5%
0.63	0.63	0.63	0.63	-0.3%	-0.3%	-0.3%	-0.3%
3.59	3.68	3.65	3.68	0.4%	0.4%	0.4%	0.5%
0.05	0.05	0.05	0.05	0.0%	0.0%	0.0%	0.0%
0.13	0.13	0.13	0.13	0.0%	0.0%	0.0%	0.0%
6.06	5.72	4.63	4.22	1.0%	0.8%	0.1%	-0.2%
10.46	**10.21**	**9.09**	**8.71**	**0.7%**	**0.6%**	**0.2%**	**0.0%**
0.26	0.32	0.50	0.57	2.8%	3.7%	5.2%	5.7%
2.38	2.30	2.26	2.34	0.4%	0.3%	0.3%	0.4%
0.46	0.46	0.47	0.47	0.5%	0.6%	0.6%	0.6%
1.64	1.22	1.09	1.19	1.1%	0.0%	-0.4%	0.0%
1.11	1.09	1.06	1.07	0.8%	0.7%	0.7%	0.7%
4.49	4.08	3.84	4.05	0.4%	0.1%	-0.1%	0.0%
10.08	9.16	8.72	9.12	0.6%	0.2%	0.1%	0.2%
11.65	10.38	10.22	10.26	1.2%	0.8%	0.7%	0.7%
1.67	1.61	1.60	1.63	0.1%	0.0%	0.0%	0.0%
3.48	3.65	3.89	3.67	1.6%	1.8%	2.0%	1.8%
4.63	3.91	3.69	4.00	1.1%	0.6%	0.4%	0.6%
31.52	**28.71**	**28.12**	**28.68**	**0.9%**	**0.6%**	**0.5%**	**0.6%**
0.15	0.17	0.18	0.18	3.9%	4.3%	4.7%	4.6%
12.67	12.64	12.64	12.64	-0.9%	-0.9%	-0.9%	-0.9%
3.42	3.42	3.29	3.42	0.4%	0.4%	0.3%	0.4%
8.05	7.90	7.52	7.67	1.1%	1.0%	0.8%	0.9%
1.12	1.11	1.10	1.11	0.2%	0.2%	0.2%	0.2%
25.40	25.24	24.74	25.02	-0.1%	-0.1%	-0.2%	-0.2%
0.81	0.78	0.72	0.72	0.5%	0.4%	0.1%	0.1%
0.96	1.05	0.80	1.20	11.5%	11.9%	10.8%	12.4%
0.00	0.00	0.00	0.00	- -	- -	- -	- -
0.07	0.07	0.07	0.07	3.9%	3.9%	3.9%	3.9%
27.25	**27.14**	**26.34**	**27.01**	**0.0%**	**0.0%**	**-0.1%**	**0.0%**
0.20	0.19	0.17	0.16	-1.4%	-1.6%	-1.9%	-2.2%
9.99	9.70	8.13	7.86	0.9%	0.8%	0.2%	0.0%
19.57	18.68	16.63	14.23	0.3%	0.1%	-0.3%	-0.8%
10.22	9.44	8.99	8.89	0.7%	0.5%	0.3%	0.3%
9.35	7.44	6.12	5.91	2.4%	1.6%	0.9%	0.8%
0.09	0.06	0.04	0.04	-1.3%	-2.4%	-3.9%	-3.9%
49.64	**45.73**	**40.31**	**37.32**	**0.8%**	**0.5%**	**0.1%**	**-0.2%**
37.23	36.07	35.06	35.67	0.0%	-0.1%	-0.2%	-0.1%
31.62	29.83	27.22	26.84	0.8%	0.6%	0.3%	0.3%
21.29	20.35	18.29	15.91	0.3%	0.1%	-0.2%	-0.7%
10.22	9.44	8.99	8.89	0.7%	0.5%	0.3%	0.3%
13.49	11.66	10.54	10.05	2.0%	1.5%	1.2%	1.0%
0.32	0.29	0.27	0.27	-0.4%	-0.6%	-0.9%	-0.9%
114.18	**107.64**	**100.37**	**97.64**	**0.5%**	**0.3%**	**0.1%**	**0.0%**

Table D1. Key results for demand sector technology cases (continued)

Consumption, emissions, combined heat and power capacity and generation	2011	2020 2012 Demand Technology	2020 Reference	2020 High Demand Technology	2020 Best Available Demand Technology	2030 2012 Demand Technology	2030 Reference	2030 High Demand Technology	2030 Best Available Demand Technology
Carbon dioxide emissions (million metric tons)									
by sector									
Residential	335	324	317	301	282	316	299	272	241
Commercial	225	230	232	230	232	234	236	234	236
Industrial[5]	905	1,039	999	988	996	1,086	1,005	987	1,007
Transportation	1,841	1,827	1,826	1,801	1,819	1,761	1,759	1,721	1,754
Electric power[11]	2,166	2,167	2,081	1,884	1,707	2,347	2,224	1,947	1,746
by fuel									
Petroleum[17]	2,299	2,287	2,270	2,232	2,254	2,206	2,169	2,116	2,153
Natural gas	1,294	1,437	1,404	1,367	1,349	1,567	1,468	1,357	1,331
Coal	1,867	1,851	1,769	1,595	1,421	1,959	1,874	1,676	1,489
Other[18]	11	11	11	11	11	11	11	11	11
Total carbon dioxide emissions	**5,471**	**5,587**	**5,455**	**5,205**	**5,035**	**5,743**	**5,523**	**5,161**	**4,984**
Residential delivered energy intensity (million Btu per household)	97	88	86	80	74	83	80	71	62
Commercial delivered energy intensity (thousand Btu per square foot)	105	102	100	96	94	100	97	89	86
Industrial delivered energy intensity (thousand Btu per 2005 dollars)	3.99	3.53	3.42	3.40	3.43	3.23	3.04	3.01	3.06
Residential sector generation									
Net summer generation capacity (megawatts)									
Natural gas	0	0	0	0	0	0	0	0	0
Solar photovoltaic	1,036	8,291	8,976	9,446	10,335	8,686	10,289	13,004	19,236
Wind	108	302	750	762	809	302	750	762	809
Electricity generation (billion kilowatthours)									
Natural gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar photovoltaic	1.63	12.72	14.01	14.75	16.14	13.35	16.10	20.53	30.54
Wind	0.15	0.43	1.08	1.09	1.16	0.43	1.08	1.09	1.16
Commercial sector generation									
Net summer generation capacity (megawatts)									
Natural gas	843	1,478	1,609	2,107	2,220	2,696	3,734	5,284	5,764
Solar photovoltaic	1,975	6,604	6,646	6,692	6,770	7,698	8,644	9,203	10,237
Wind	97	108	118	120	124	132	302	283	309
Electricity generation (billion kilowatthours)									
Natural gas	6.13	10.75	11.70	15.32	16.15	19.61	27.16	38.44	41.93
Solar photovoltaic	3.07	10.34	10.50	10.57	10.70	12.08	13.79	14.72	16.39
Wind	0.12	0.14	0.15	0.16	0.16	0.17	0.43	0.40	0.44

[1]Includes propane, kerosene, and distillate fuel oil.
[2]Includes wood used for residential heating.
[3]Includes propane, motor gasoline (including ethanol (blends of 15 percent or less) and ethers blended in), kerosene, distillate fuel oil, and residual fuel oil.
[4]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes motor gasoline (including ethanol (blends of 15 percent or less) and ethers blended in), residual fuel oil, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[10]Includes propane, residual fuel oil, aviation gasoline, and lubricants.
[11]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[12]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[13]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[14]Includes non-biogenic municipal waste not included above.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[17]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2009, international bunker fuels accounted for 90 to 126 million metric tons annually.
[18]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2013 National Energy Modeling System, runs FROZTECH.D120712A, REF2013.D102312A, HIGHTECH.D120712A, and BESTTECH.D121012A.

2040				Annual Growth 2011-2040 (percent)			
2012 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2012 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
307	282	250	215	-0.3%	-0.6%	-1.0%	-1.5%
240	245	243	245	0.2%	0.3%	0.3%	0.3%
1,157	1,040	1,011	1,033	0.8%	0.5%	0.4%	0.5%
1,818	1,809	1,756	1,796	0.0%	-0.1%	-0.2%	-0.1%
2,416	2,315	2,036	1,792	0.4%	0.2%	-0.2%	-0.7%
2,236	2,175	2,114	2,145	-0.1%	-0.2%	-0.3%	-0.2%
1,665	1,569	1,431	1,411	0.9%	0.7%	0.3%	0.3%
2,025	1,936	1,739	1,514	0.3%	0.1%	-0.2%	-0.7%
11	11	11	11	0.0%	0.0%	0.0%	0.0%
5,938	**5,691**	**5,296**	**5,081**	**0.3%**	**0.1%**	**-0.1%**	**-0.3%**
81	76	67	56	-0.6%	-0.9%	-1.3%	-1.9%
96	94	84	80	-0.3%	-0.4%	-0.8%	-0.9%
2.97	2.74	2.72	2.76	-1.0%	-1.3%	-1.3%	-1.3%
2	2	2	2	- -	- -	- -	- -
9,649	12,927	20,651	37,759	8.0%	9.1%	10.9%	13.2%
303	751	764	818	3.6%	6.9%	7.0%	7.2%
0.00	0.00	0.00	0.00	- -	- -	- -	- -
14.84	20.38	32.96	60.49	7.9%	9.1%	10.9%	13.3%
0.43	1.08	1.10	1.17	3.7%	7.0%	7.0%	7.3%
4,951	8,437	12,017	12,626	6.3%	8.3%	9.5%	9.7%
10,091	12,141	14,213	19,129	5.8%	6.5%	7.0%	8.1%
334	762	765	950	4.4%	7.4%	7.4%	8.2%
36.01	61.37	87.42	91.85	6.3%	8.3%	9.5%	9.7%
15.85	19.56	22.95	30.74	5.8%	6.6%	7.2%	8.3%
0.47	1.07	1.07	1.32	4.7%	7.7%	7.7%	8.5%

Table D2. Energy consumption and carbon dioxide emissions for extended policy cases

Consumption and emissions	2011	2020			2030			2040		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Energy consumption by sector (quadrillion Btu)										
Residential	11.28	10.95	10.91	10.72	11.20	11.01	10.41	11.57	11.29	10.37
Commercial	8.60	8.95	8.95	8.85	9.54	9.55	9.17	10.21	10.26	9.67
Industrial[1]	24.04	26.87	26.90	26.88	27.40	27.51	27.45	28.71	28.98	28.56
Transportation	27.09	27.24	27.23	27.21	26.25	26.25	25.99	27.14	27.17	26.06
Electric power[2]	39.40	40.57	40.38	39.64	43.02	42.69	41.16	45.73	45.70	43.63
Total	**97.70**	**101.04**	**100.89**	**100.06**	**102.81**	**102.62**	**100.33**	**107.64**	**107.92**	**103.54**
Energy consumption by fuel (quadrillion Btu)										
Liquid fuels and other petroleum[3]	37.02	37.54	37.54	37.50	36.08	36.10	35.78	36.07	36.10	34.76
Natural gas	24.91	26.77	26.71	26.60	27.95	27.60	26.82	29.83	28.60	27.54
Coal	19.66	18.59	18.35	17.84	19.70	19.20	18.45	20.35	19.84	19.00
Nuclear / uranium	8.26	9.25	9.25	9.25	9.49	9.49	9.49	9.44	9.08	9.02
Renewable energy[4]	7.49	8.58	8.74	8.57	9.31	9.98	9.52	11.66	14.03	12.95
Other[5]	0.35	0.31	0.31	0.31	0.28	0.26	0.26	0.29	0.28	0.27
Total	**97.70**	**101.04**	**100.89**	**100.06**	**102.81**	**102.62**	**100.33**	**107.64**	**107.92**	**103.54**
Energy intensity (thousand Btu per 2005 dollar of GDP)	7.35	5.99	5.98	5.94	4.81	4.80	4.70	3.95	3.95	3.80
Carbon dioxide emissions by sector (million metric tons)										
Residential	335	317	317	315	299	298	285	282	280	256
Commercial	225	232	232	230	236	238	229	245	248	233
Industrial[1]	905	999	1,000	999	1,005	1,009	1,000	1,040	1,051	1,025
Transportation	1,841	1,826	1,826	1,824	1,759	1,759	1,742	1,809	1,810	1,736
Electric power[2]	2,166	2,081	2,052	2,001	2,224	2,152	2,065	2,315	2,187	2,103
Total	**5,471**	**5,455**	**5,428**	**5,370**	**5,523**	**5,456**	**5,321**	**5,691**	**5,575**	**5,353**
Carbon dioxide emissions by fuel (million metric tons)										
Petroleum	2,299	2,270	2,269	2,267	2,169	2,169	2,146	2,175	2,173	2,086
Natural gas	1,294	1,404	1,401	1,395	1,468	1,449	1,408	1,569	1,504	1,448
Coal	1,867	1,769	1,746	1,698	1,874	1,826	1,756	1,936	1,887	1,807
Other[6]	11	11	11	11	11	11	11	11	11	11
Total	**5,471**	**5,455**	**5,428**	**5,370**	**5,523**	**5,456**	**5,321**	**5,691**	**5,575**	**5,353**
Carbon dioxide emissions (tons per person)	**17.5**	**16.0**	**15.9**	**15.8**	**14.8**	**14.6**	**14.3**	**14.1**	**13.8**	**13.2**

[1]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste, net electricity imports, and liquid hydrogen.
[6]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D041713A.

Table D3. Electricity generation and generating capacity in extended policy cases
(gigawatts, unless otherwise noted)

Net summer capacity, generation, consumption, and emissions	2011	2020			2030			2040		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Capacity	**1,048.8**	**1,068.1**	**1,071.3**	**1,038.6**	**1,147.0**	**1,167.8**	**1,102.4**	**1,293.3**	**1,378.0**	**1,264.3**
Electric power sector[1]	1,018.1	1,019.6	1,013.5	980.4	1,085.8	1,070.5	1,005.5	1,212.3	1,233.0	1,121.3
Pulverized coal	313.9	271.0	262.4	252.1	270.1	262.1	251.8	271.3	262.1	251.8
Coal gasification combined-cycle	0.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Oil and natural gas steam	102.7	87.2	84.7	72.9	69.9	64.4	53.6	64.8	56.8	40.9
Conventional natural gas combined-cycle	205.5	216.7	216.7	216.4	221.8	220.4	219.3	227.6	225.1	222.3
Advanced natural gas combined-cycle	0.0	2.5	1.6	1.0	42.5	26.2	17.3	86.8	57.4	43.8
Conventional combustion turbine	138.9	137.8	135.4	133.7	137.1	133.8	130.4	136.9	133.3	130.2
Advanced combustion turbine	0.0	14.9	11.2	9.0	42.8	35.7	19.4	74.8	67.0	37.6
Nuclear / uranium	101.1	110.6	110.6	110.6	113.6	113.6	113.6	113.1	108.5	107.8
Pumped storage	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	133.1	153.8	166.1	159.9	160.5	188.1	174.6	207.6	294.8	260.6
Distributed generation	0.0	0.9	0.6	0.4	3.1	2.0	1.2	5.1	3.6	2.0
Combined heat and power[2]	30.6	48.5	57.8	58.2	61.1	97.2	96.9	81.0	145.0	143.0
Fossil fuels / other	21.7	24.4	25.3	25.5	32.0	34.8	34.2	43.5	47.6	46.2
Renewable fuels	8.9	24.2	32.5	32.6	29.1	62.4	62.6	37.5	97.4	96.9
Cumulative additions	**0.0**	**87.6**	**103.9**	**94.8**	**182.2**	**219.6**	**178.6**	**339.9**	**443.8**	**359.4**
Electric power sector[1]	0.0	69.7	76.7	67.3	151.7	153.0	112.3	289.5	329.4	247.0
Pulverized coal	0.0	4.9	4.9	4.9	4.9	4.9	4.9	6.1	4.9	4.9
Coal gasification combined-cycle	0.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Conventional natural gas combined-cycle	0.0	11.4	11.4	11.2	16.5	15.2	14.1	22.4	19.9	17.0
Advanced natural gas combined-cycle	0.0	2.5	1.6	1.0	42.5	26.2	17.3	86.8	57.4	43.8
Conventional combustion turbine	0.0	6.1	5.8	5.6	6.1	5.8	5.6	6.1	5.8	5.6
Advanced combustion turbine	0.0	14.9	11.2	9.0	42.8	35.7	19.4	74.8	67.0	37.6
Nuclear / uranium	0.0	5.5	5.5	5.5	5.5	5.5	5.5	11.0	6.5	5.7
Renewable sources	0.0	21.8	34.2	28.0	28.6	56.2	42.7	75.7	162.9	128.7
Distributed generation	0.0	0.9	0.6	0.4	3.1	2.0	1.2	5.1	3.6	2.0
Combined heat and power[2]	0.0	17.9	27.1	27.5	30.5	66.6	66.2	50.4	114.4	112.4
Fossil fuels / other	0.0	2.7	3.5	3.8	10.3	13.1	12.5	21.8	25.9	24.5
Renewable fuels	0.0	15.2	23.6	23.7	20.2	53.5	53.7	28.6	88.5	87.9
Cumulative retirements	**0.0**	**72.7**	**85.9**	**109.5**	**92.0**	**108.6**	**133.0**	**103.4**	**122.6**	**151.9**
Generation by fuel (billion kilowatthours)	**4,093**	**4,389**	**4,388**	**4,317**	**4,777**	**4,786**	**4,613**	**5,212**	**5,254**	**5,026**
Electric power sector[1]	3,954	4,182	4,162	4,089	4,506	4,446	4,277	4,842	4,765	4,548
Coal	1,715	1,640	1,617	1,570	1,745	1,699	1,635	1,804	1,756	1,686
Petroleum	26	15	15	15	16	15	15	16	16	16
Natural gas	930	1,078	1,065	1,057	1,221	1,144	1,086	1,348	1,122	1,082
Nuclear / uranium	790	885	885	885	908	908	908	903	868	863
Renewable sources	489	559	575	558	602	670	625	754	992	894
Pumped storage / other	4	2	2	2	3	3	3	3	3	3
Distributed generation	0	3	2	1	10	7	4	13	8	5
Combined heat and power[2]	139	208	226	228	271	340	336	370	489	478
Fossil fuels / other	103	140	145	146	189	205	201	266	290	280
Renewable fuels	36	68	81	82	82	135	136	104	199	198
Average electricity price (cents per kilowatthour)	**9.9**	**9.4**	**9.4**	**9.4**	**9.7**	**9.6**	**9.5**	**10.8**	**10.4**	**10.1**

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D041713A.

Table D4. Key results for nuclear plant cases
(gigawatts, unless otherwise noted)

Net summer capacity, generation, emissions, and fuel prices	2011	2030 Low Nuclear	2030 Reference	2030 High Nuclear	2030 Small Modular Reactor	2040 Low Nuclear	2040 Reference	2040 High Nuclear	2040 Small Modular Reactor
Capacity									
Coal steam	314.4	273.7	272.1	272.3	271.7	278.7	273.3	273.4	272.7
Oil and natural gas steam	102.7	67.3	69.9	70.4	68.7	62.0	64.8	64.8	65.1
Combined cycle	205.5	264.4	264.3	258.3	264.0	337.0	314.4	301.3	312.8
Combustion turbine / diesel	138.9	183.5	179.9	179.9	182.1	218.6	211.7	218.1	212.9
Nuclear / uranium	101.1	102.8	113.6	121.9	113.7	62.6	113.1	127.2	115.4
Pumped storage	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	133.1	160.9	160.5	160.2	160.5	211.3	207.6	202.9	204.9
Distributed generation	0.0	2.6	3.1	3.2	3.1	4.1	5.1	5.3	5.1
Combined heat and power[1]	30.6	61.9	61.1	61.1	61.2	83.4	81.0	80.4	81.1
Total	**1,048.8**	**1,139.6**	**1,147.0**	**1,149.6**	**1,147.4**	**1,280.1**	**1,293.3**	**1,295.9**	**1,292.3**
Cumulative additions									
Coal steam	0.0	6.4	6.4	6.4	6.4	11.4	7.6	7.5	7.5
Oil and natural gas steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle	0.0	59.2	59.0	53.1	58.8	131.8	109.1	96.1	107.6
Combustion turbine / diesel	0.0	51.9	48.9	48.4	51.3	87.0	80.9	86.7	82.5
Nuclear / uranium	0.0	5.5	5.5	13.3	5.6	5.5	11.0	18.7	13.3
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	0.0	29.0	28.6	28.3	28.6	79.4	75.7	71.0	73.0
Distributed generation	0.0	2.6	3.1	3.2	3.1	4.1	5.1	5.3	5.1
Combined heat and power[1]	0.0	31.3	30.5	30.4	30.6	52.8	50.4	49.8	50.5
Total	**0.0**	**186.0**	**182.2**	**183.1**	**184.5**	**372.0**	**339.9**	**335.1**	**339.5**
Cumulative retirements	**0.0**	**96.6**	**92.0**	**90.3**	**93.9**	**142.0**	**103.4**	**96.0**	**103.9**
Generation by fuel (billion kilowatthours)									
Coal	1,715	1,771	1,745	1,734	1,740	1,846	1,804	1,804	1,801
Petroleum	26	16	16	16	16	16	16	16	16
Natural gas	930	1,267	1,221	1,181	1,225	1,602	1,348	1,272	1,338
Nuclear / uranium	790	824	908	974	909	507	903	1,014	921
Pumped storage / other	4	3	3	3	3	3	3	3	3
Renewable sources	489	599	602	600	601	770	754	741	748
Distributed generation	0	9	10	10	11	12	13	14	14
Combined heat and power[1]	139	275	271	272	272	381	370	368	370
Total	**4,093**	**4,764**	**4,777**	**4,789**	**4,775**	**5,136**	**5,212**	**5,231**	**5,211**
Carbon dioxide emissions by the electric power sector (million metric tons)[2]									
Petroleum	25	14	14	14	14	14	14	14	14
Natural gas	411	500	482	468	483	602	514	489	511
Coal	1,718	1,743	1,717	1,707	1,713	1,812	1,775	1,776	1,773
Other[3]	11	11	11	11	11	11	11	11	11
Total	**2,166**	**2,267**	**2,224**	**2,201**	**2,221**	**2,440**	**2,315**	**2,291**	**2,310**
Prices to the electric power sector[2] (2011 dollars per million Btu)									
Petroleum	17.49	28.20	28.23	28.24	28.18	33.49	33.49	33.47	33.47
Natural gas	4.77	6.20	6.05	5.95	6.07	9.36	8.38	8.36	8.51
Coal	2.38	2.88	2.87	2.86	2.86	3.23	3.20	3.20	3.20

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs LOWNUC13.D112112A, REF2013.D102312A, HINUC13.D112112A, and NUCSMR13.D112712A.

Table D5. Key results for renewable technology case

Capacity, generation, and emissions	2011	2020		2030		2040	
		Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost
Net summer capacity (gigawatts)							
Electric power sector[1]							
Conventional hydropower	77.87	78.34	78.68	79.11	79.75	80.31	82.06
Geothermal[2]	2.38	3.63	3.37	5.70	6.20	7.46	7.94
Municipal waste[3]	3.34	3.44	3.44	3.44	3.44	3.44	3.44
Wood and other biomass[4]	2.37	2.82	2.81	2.85	3.22	3.70	6.18
Solar thermal	0.49	1.35	1.35	1.35	1.35	1.35	1.35
Solar photovoltaic	1.01	5.37	10.15	6.80	15.08	24.54	45.95
Wind	45.68	58.81	64.67	61.30	70.37	86.83	116.68
Total	**133.14**	**153.75**	**164.48**	**160.54**	**179.40**	**207.63**	**263.61**
End-use sector[5]							
Conventional hydropower	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[6]	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Wood and other biomass	4.92	6.87	7.61	8.34	10.36	10.18	14.01
Solar photovoltaic	3.02	15.63	16.81	18.94	23.22	25.08	33.51
Wind	0.21	0.87	1.36	1.05	1.73	1.51	2.84
Total	**8.93**	**24.15**	**26.55**	**29.12**	**36.10**	**37.55**	**51.15**
Generation (billion kilowatthours)							
Electric power sector[1]							
Coal	1,715	1,640	1,609	1,745	1,709	1,804	1,758
Petroleum	26	15	15	16	16	16	16
Natural gas	930	1,078	1,062	1,221	1,184	1,348	1,238
Total fossil	2,671	2,733	2,686	2,982	2,908	3,169	3,013
Conventional hydropower	323.14	288.54	290.00	292.39	295.25	297.28	303.59
Geothermal	16.70	25.28	23.25	42.02	46.15	56.40	60.51
Municipal waste[7]	16.62	14.09	14.09	14.09	14.09	14.10	14.10
Wood and other biomass[4]	10.50	54.45	72.77	65.48	86.74	75.64	113.52
Dedicated plants	9.35	14.85	14.75	15.30	17.96	21.59	39.64
Cofiring	1.16	39.60	58.03	50.18	68.78	54.05	73.88
Solar thermal	0.81	2.74	2.74	2.73	2.74	2.73	2.73
Solar photovoltaic	0.97	9.83	20.85	13.40	32.67	56.22	105.76
Wind	119.63	163.48	182.60	172.11	199.32	251.94	340.16
Total renewable	**488.38**	**558.41**	**606.30**	**602.22**	**676.96**	**754.32**	**940.37**
End-use sector[5]							
Total fossil	88	122	122	171	169	248	242
Conventional hydropower[8]	1.89	1.82	1.82	1.82	1.82	1.82	1.82
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[6]	2.04	3.55	3.55	3.55	3.55	3.55	3.55
Wood and other biomass	26.75	36.95	40.54	45.55	56.25	56.25	77.56
Solar photovoltaic	4.71	24.53	26.37	29.91	36.82	39.97	53.71
Wind	0.28	1.23	1.87	1.50	2.41	2.15	3.93
Total renewable	**35.68**	**68.09**	**74.14**	**82.33**	**100.85**	**103.74**	**140.57**
Carbon dioxide emissions by the electric power sector (million metric tons)[1]							
Coal	1,718	1,610	1,580	1,717	1,681	1,775	1,730
Petroleum	25	13	13	14	14	14	14
Natural gas	411	446	440	482	471	514	476
Other [9]	11	11	11	11	11	11	11
Total	**2,166**	**2,081**	**2,044**	**2,224**	**2,177**	**2,315**	**2,232**

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[8]Represents own-use industrial hydroelectric power.
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs REF2013.D102312A, and LCR20.D112012A.

Table D6. Key results for environmental cases

Net summer capacity, generation, emissions, and fuel prices	2011	2040							
		Reference	GHG10	GHG15	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices	GHG15 and Low Gas Prices	GHG25 and Low Gas Prices
Capacity (gigawatts)									
Coal steam	314.4	273.3	219.6	120.1	28.8	248.0	145.5	80.7	29.5
Oil and natural gas steam	102.7	64.8	51.7	37.9	26.0	68.5	57.6	56.2	19.9
Combined cycle	205.5	314.4	312.8	336.2	368.3	343.6	433.4	458.7	517.1
Combustion turbine / diesel	138.9	211.7	200.3	192.5	174.0	250.3	213.4	201.5	176.7
Nuclear / uranium	101.1	113.1	137.3	166.5	226.6	106.5	115.9	130.7	150.5
Pumped storage	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3
Renewable sources	133.1	207.6	264.4	375.5	439.0	162.3	197.2	260.7	325.5
Distributed generation	0.0	5.1	0.2	0.0	0.0	28.2	0.3	0.1	0.0
Combined heat and power[1]	30.6	81.0	91.8	99.1	108.3	85.1	93.2	96.4	103.2
Total	**1,048.8**	**1,293.3**	**1,300.4**	**1,350.2**	**1,393.3**	**1,314.8**	**1,278.8**	**1,307.2**	**1,344.6**
Cumulative additions (gigawatts)									
Coal steam	0.0	7.6	6.4	7.2	6.5	6.4	6.4	6.4	6.4
Combined cycle	0.0	109.1	107.6	131.0	163.0	138.4	228.1	253.5	311.8
Combustion turbine / diesel	0.0	80.9	70.5	69.1	71.1	116.3	82.0	72.9	72.7
Nuclear / uranium	0.0	11.0	35.3	64.4	124.6	5.5	13.9	28.6	48.5
Renewable sources	0.0	75.7	132.5	243.6	307.1	30.4	65.3	128.8	193.6
Distributed generation	0.0	5.1	0.2	0.0	0.0	28.2	0.3	0.1	0.0
Combined heat and power[1]	0.0	50.4	61.2	68.5	77.6	54.5	62.6	65.8	72.5
Total	**0.0**	**339.9**	**413.6**	**583.9**	**750.0**	**379.7**	**458.6**	**556.0**	**705.5**
Cumulative retirements (gigawatts)	**0.0**	**103.4**	**170.0**	**290.5**	**413.5**	**121.7**	**236.5**	**305.6**	**417.7**
Generation by fuel (billion kilowatthours)									
Coal	1,715	1,804	1,190	602	61	1,426	550	176	32
Petroleum	26	16	15	12	10	16	12	10	10
Natural gas	930	1,348	1,240	1,263	1,105	1,971	2,473	2,491	2,189
Nuclear / uranium	790	903	1,091	1,317	1,788	853	925	1,039	1,195
Pumped storage / other	4	3	3	3	3	3	3	3	3
Renewable sources	489	754	1,070	1,277	1,382	633	772	912	1,077
Distributed generation	0	13	0	0	0	122	0	0	0
Combined heat and power[1]	139	370	417	437	463	409	441	452	473
Total	**4,093**	**5,212**	**5,026**	**4,911**	**4,812**	**5,432**	**5,177**	**5,083**	**4,977**
Emissions by the electric power sector[2]									
Carbon dioxide (million metric tons)	2,166	2,315	1,639	1,034	360	2,227	1,444	1,056	544
Sulfur dioxide (million short tons)	4.42	1.66	0.90	0.47	0.06	1.09	0.40	0.13	0.04
Nitrogen oxides (million short tons)	1.94	1.87	1.31	0.70	0.26	1.56	0.72	0.41	0.30
Mercury (short tons)	31.49	7.75	5.32	2.81	0.53	6.16	2.39	0.97	0.37
Retrofits (gigawatts)									
Scrubber	0.00	33.87	36.06	20.75	15.76	33.92	22.05	17.32	14.36
Nitrogen oxide controls									
Combustion	0.00	0.79	0.79	0.79	0.01	0.78	0.00	0.01	0.00
Selective catalytic reduction post-combustion	0.00	13.90	12.28	13.65	14.17	13.52	14.12	12.28	12.31
Selective non-catalytic reduction post-combustion	0.00	0.70	1.22	1.17	0.70	2.51	1.17	0.70	0.70
Prices to the electric power sector[2] (2011 dollars per million Btu)									
Natural gas	4.77	8.38	10.03	11.01	12.87	5.13	7.47	8.47	10.40
Coal	2.38	3.20	6.38	7.71	10.58	2.91	5.83	7.25	10.75

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
Btu = British thermal unit.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs REF2013.D102312A, CO2FEE10.D021413A, CO2FEE15.D021413A, CO2FEE25.D021413A, HIGHRESOURCE.D021413A, CO2FEE10HR.D021413A, CO2FEE15HR.D021413A, and CO2FEE25HR.D021413A.

Table D7. Natural gas supply and disposition, oil and gas resource cases
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	2011	2020 Low Oil and Gas Resource	2020 Reference	2020 High Oil and Gas Resource	2030 Low Oil and Gas Resource	2030 Reference	2030 High Oil and Gas Resource	2040 Low Oil and Gas Resource	2040 Reference	2040 High Oil and Gas Resource
Henry Hub spot price										
(2011 dollars per million Btu)	3.98	5.37	4.13	2.72	7.05	5.40	3.26	10.36	7.83	4.32
(2011 dollars per thousand cubic feet)	4.07	5.49	4.22	2.78	7.21	5.52	3.33	10.59	8.00	4.42
Dry gas production[1]	**23.00**	**24.23**	**26.61**	**30.94**	**25.75**	**29.79**	**36.89**	**27.03**	**33.14**	**44.91**
Lower 48 onshore	20.54	21.84	24.27	28.37	21.85	26.26	33.30	22.47	29.12	40.74
Associated-dissolved[2]	1.54	1.78	2.14	3.00	1.24	1.43	3.05	0.93	1.09	2.70
Non-associated	19.00	20.06	22.13	25.37	20.62	24.83	30.25	21.54	28.03	38.04
Tight gas	5.86	5.98	6.40	7.63	5.77	6.67	8.86	5.95	7.34	10.72
Shale gas	7.85	9.29	11.05	13.18	10.40	14.17	17.56	11.14	16.70	23.93
Coalbed methane	1.71	1.79	1.71	1.60	2.15	1.69	1.51	2.55	2.11	1.53
Other	3.58	2.99	2.97	2.96	2.30	2.31	2.32	1.90	1.87	1.86
Lower 48 offshore	2.11	2.11	2.07	2.29	2.70	2.34	2.37	3.38	2.85	2.92
Associated-dissolved[2]	0.54	0.66	0.66	0.74	0.71	0.60	0.65	0.89	0.74	0.81
Non-associated	1.58	1.44	1.41	1.55	1.99	1.73	1.72	2.49	2.11	2.12
Alaska	0.35	0.28	0.28	0.28	1.19	1.19	1.22	1.18	1.18	1.25
Supplemental natural gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net imports	**1.95**	**0.24**	**-0.14**	**-0.52**	**-0.83**	**-2.10**	**-3.63**	**-2.56**	**-3.55**	**-6.70**
Pipeline[4]	1.67	0.50	0.13	-0.26	0.04	-0.67	-1.57	-1.39	-2.09	-2.84
Liquefied natural gas	0.28	-0.26	-0.26	-0.26	-0.87	-1.43	-2.06	-1.17	-1.46	-3.86
Total supply	**25.01**	**24.53**	**26.54**	**30.48**	**24.98**	**27.75**	**33.33**	**24.53**	**29.65**	**38.27**
Consumption by sector										
Residential	4.72	4.44	4.52	4.64	4.26	4.36	4.52	4.02	4.14	4.31
Commercial	3.16	3.20	3.32	3.51	3.26	3.42	3.71	3.40	3.60	3.97
Industrial[5]	6.77	7.52	7.68	7.96	7.55	7.79	8.04	7.59	7.90	8.14
Natural-gas-to-liquids heat and power[6]	0.00	0.07	0.13	0.14	0.09	0.21	0.36	0.11	0.33	1.01
Natural gas to liquids production[7]	0.00	0.07	0.14	0.15	0.09	0.22	0.39	0.12	0.35	1.10
Electric power[8]	7.60	6.87	8.23	11.27	7.23	8.89	12.89	6.13	9.50	14.78
Transportation[9]	0.04	0.07	0.08	0.08	0.18	0.26	0.27	0.77	1.04	1.04
Pipeline fuel	0.68	0.66	0.70	0.78	0.67	0.73	0.85	0.66	0.76	0.97
Lease and plant fuel[10]	1.39	1.42	1.54	1.74	1.46	1.70	2.12	1.59	1.93	2.79
Total	**24.37**	**24.31**	**26.32**	**30.26**	**24.78**	**27.57**	**33.14**	**24.40**	**29.54**	**38.11**
Discrepancy[11]	0.64	0.22	0.22	0.22	0.19	0.18	0.19	0.14	0.12	0.16
Lower 48 end of year dry reserves[1]	**298.96**	**308.37**	**332.51**	**398.38**	**321.33**	**350.65**	**435.34**	**330.37**	**359.97**	**450.88**

[1]Marketed production (wet) minus extraction losses.
[2]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[7]Includes any natural gas converted into liquid fuel.
[8]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[9]Natural gas used as a vehicle fuel.
[10]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[11]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2011 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 supply values; lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2011 consumption based on: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 natural gas price at Henry Hub based on daily spot prices published in Natural Gas Intelligence. **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWRESOURCE.D012813A, REF2013.D102312A, and HIGHRESOURCE.D021413A.

Table D8. Liquid fuels supply and disposition, oil and gas resource cases
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2011	2020			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Crude oil prices (2011 dollars per barrel)										
Brent spot	111.26	107.96	105.57	98.30	132.32	130.47	117.09	165.01	162.68	143.97
West Texas Intermediate spot	94.86	105.92	103.57	96.43	130.29	128.47	115.30	162.98	160.68	142.20
Imported crude oil[1]	102.65	104.36	102.19	95.26	126.68	125.64	112.93	157.23	154.96	136.97
Crude oil supply										
Domestic production[2]	5.67	6.82	7.47	9.68	5.96	6.30	9.96	5.90	6.13	10.24
Alaska	0.57	0.49	0.49	0.54	0.38	0.38	0.69	0.41	0.41	0.89
Lower 48 States	5.10	6.33	6.98	9.14	5.57	5.92	9.27	5.49	5.72	9.35
Net imports	8.89	7.55	6.82	4.57	7.89	7.36	3.74	8.12	7.57	3.09
Gross imports	8.94	7.55	6.82	4.57	7.89	7.36	3.74	8.12	7.57	3.09
Exports	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other crude oil supply[3]	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude oil supply	**14.81**	**14.37**	**14.29**	**14.24**	**13.85**	**13.66**	**13.70**	**14.02**	**13.70**	**13.33**
Other petroleum supply	**3.02**	**3.90**	**4.04**	**4.40**	**3.65**	**3.82**	**4.30**	**3.17**	**3.29**	**3.96**
Natural gas plant liquids	2.22	2.77	3.13	4.13	2.46	2.90	4.69	2.40	2.92	5.02
Net product imports	-0.30	0.06	-0.13	-0.68	0.15	-0.08	-1.22	-0.32	-0.67	-1.82
Gross refined product imports[4]	1.15	1.46	1.47	1.42	1.71	1.53	1.36	1.67	1.42	1.30
Unfinished oil imports	0.69	0.56	0.56	0.56	0.51	0.51	0.51	0.45	0.45	0.45
Blending component imports	0.72	0.63	0.63	0.63	0.54	0.54	0.45	0.42	0.40	0.37
Exports	2.86	2.60	2.79	3.30	2.62	2.67	3.53	2.86	2.94	3.94
Refinery processing gain[5]	1.08	1.08	1.04	0.95	1.04	1.00	0.82	1.08	1.03	0.77
Product stock withdrawal	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**1.09**	**1.47**	**1.51**	**1.50**	**1.48**	**1.58**	**1.60**	**1.79**	**1.97**	**2.25**
Supply from renewable sources	0.90	1.18	1.18	1.19	1.13	1.14	1.16	1.40	1.43	1.38
Ethanol	0.84	1.07	1.08	1.09	0.99	0.99	1.02	0.95	0.97	0.99
Domestic production	0.91	1.00	1.01	1.02	0.95	0.95	0.98	0.86	0.89	0.93
Net imports	-0.07	0.07	0.07	0.07	0.04	0.04	0.04	0.10	0.08	0.06
Biodiesel	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Domestic production	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net imports	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other biomass-derived liquids[6]	0.00	0.02	0.02	0.02	0.06	0.06	0.06	0.37	0.38	0.32
Liquids from gas	0.00	0.04	0.08	0.08	0.05	0.13	0.22	0.07	0.20	0.62
Liquids from coal	0.00	0.00	0.00	0.00	0.02	0.04	0.00	0.03	0.06	0.04
Other[7]	0.18	0.26	0.25	0.23	0.28	0.28	0.22	0.29	0.28	0.20
Total primary supply[8]	**18.92**	**19.74**	**19.84**	**20.15**	**18.98**	**19.06**	**19.59**	**18.99**	**18.96**	**19.55**
Net import share of product supplied (percent)	45.0	39.0	34.1	19.7	42.7	38.5	13.1	41.7	36.9	6.9
Net expenditures for imports of crude oil and petroleum products (billion 2011 dollars)	362.66	293.15	259.66	163.99	370.21	342.67	158.79	471.38	433.65	159.39
Lower 48 end of year reserves[2] (billion barrels)	**21.36**	**23.07**	**24.63**	**29.69**	**24.11**	**24.92**	**31.36**	**26.03**	**26.72**	**32.75**

Table D8. Liquid fuels supply and disposition, oil and gas resource cases (continued)

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2011	2020			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Refined petroleum product prices to the transportation sector (2011 dollars per gallon)										
Propane	2.22	2.18	2.07	1.73	2.34	2.26	1.94	2.50	2.44	2.24
Ethanol (E85)[9]	2.42	2.89	2.83	2.73	2.61	2.57	2.35	3.14	2.92	2.74
Ethanol wholesale price	2.54	3.05	3.00	2.95	2.36	2.28	2.27	2.61	2.48	2.27
Motor gasoline[10]	3.45	3.38	3.32	3.16	3.72	3.67	3.39	4.39	4.32	3.93
Jet fuel[11]	3.04	2.97	2.90	2.70	3.59	3.51	3.16	4.34	4.19	3.71
Distillate fuel oil[12]	3.58	3.71	3.65	3.45	4.28	4.22	3.94	5.05	4.94	4.47
Residual fuel oil	2.67	2.29	2.23	2.07	2.78	2.75	2.46	3.44	3.36	2.98
Residual fuel oil (2011 dollars per barrel)	112.11	96.00	93.74	87.03	116.81	115.30	103.28	144.39	141.16	125.08

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[4]Includes other hydrocarbons and alcohol.
[5]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[6]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[7]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[8]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[9]E85 refers to a blend of 85 pecent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[11]Includes only kerosene-type.
[12]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 crude oil spot prices: Thomson Reuters. 2011 transportation sector prices based on: EIA, Form EIA-782A, “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report”. 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2011 wholesale ethanol prices derived from Bloomberg U.S. average rack price. Other 2011 data: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWRESOURCE.D012813A, REF2013.D102312A, and HIGHRESOURCE.D021413A.

Table D9. Key transportation results, oil and gas resource cases

Consumption and indicators	2011	2020 Low Oil and Gas Resource	2020 Reference	2020 High Oil and Gas Resource	2030 Low Oil and Gas Resource	2030 Reference	2030 High Oil and Gas Resource	2040 Low Oil and Gas Resource	2040 Reference	2040 High Oil and Gas Resource
Level of travel										
(billion vehicle miles traveled)										
Light-duty vehicles less than 8,501 pounds	2,629	2,860	2,870	2,901	3,312	3,323	3,372	3,711	3,719	3,775
Commercial light trucks[1]	65	80	80	81	94	94	96	109	110	112
Freight trucks greater than 10,000 pounds	240	321	323	332	369	371	385	437	438	454
(billion seat miles available)										
Air	982	1,081	1,082	1,082	1,177	1,177	1,177	1,274	1,274	1,274
(billion ton miles traveled)										
Rail	1,557	1,755	1,719	1,622	1,909	1,910	1,772	2,000	2,017	1,947
Domestic shipping	514	594	612	703	567	578	737	581	591	773
Energy efficiency indicators										
(miles per gallon)										
Tested new light-duty vehicle[2]	31.5	38.0	37.9	37.7	48.2	48.1	47.7	49.1	49.0	48.5
New car[2]	36.4	44.4	44.4	44.3	55.6	55.6	55.5	56.1	56.1	55.9
New light truck[2]	27.3	32.1	32.0	31.9	40.4	40.3	40.1	40.5	40.4	40.1
On-road new light-duty vehicle[3]	25.5	30.7	30.6	30.4	39.0	38.9	38.6	39.7	39.7	39.3
New car[3]	29.8	36.3	36.3	36.2	45.4	45.4	45.3	45.8	45.8	45.7
New light truck[3]	21.8	25.7	25.6	25.5	32.4	32.3	32.1	32.4	32.3	32.1
Light-duty stock[4]	20.6	24.1	24.1	24.0	31.4	31.3	31.2	36.2	36.1	35.8
New commercial light truck[1]	18.1	20.0	20.0	19.9	24.2	24.1	24.0	24.2	24.2	24.0
Stock commercial light truck[1]	14.9	17.9	17.9	17.9	22.2	22.2	22.1	24.1	24.1	23.9
Freight truck	6.7	7.3	7.3	7.3	8.0	8.0	8.0	8.2	8.2	8.1
(seat miles per gallon)										
Aircraft	62.3	63.9	63.9	63.9	67.0	67.0	67.0	71.5	71.5	71.5
(ton miles per thousand Btu)										
Rail	3.4	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Domestic shipping	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6
Energy use by mode (quadrillion Btu)										
Light-duty vehicles	15.56	14.29	14.35	14.53	12.71	12.77	13.02	12.38	12.43	12.72
Commercial light trucks[1]	0.54	0.56	0.56	0.57	0.53	0.53	0.54	0.57	0.57	0.58
Bus transportation	0.25	0.27	0.27	0.27	0.29	0.29	0.29	0.32	0.32	0.32
Freight trucks	4.95	6.02	6.07	6.24	6.34	6.39	6.64	7.27	7.31	7.62
Rail, passenger	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Rail, freight	0.45	0.51	0.49	0.47	0.54	0.54	0.50	0.56	0.57	0.55
Shipping, domestic	0.21	0.24	0.25	0.29	0.23	0.23	0.30	0.23	0.23	0.30
Shipping, international	0.80	0.81	0.81	0.81	0.82	0.82	0.82	0.84	0.84	0.84
Recreational boats	0.24	0.26	0.26	0.26	0.27	0.28	0.28	0.29	0.29	0.30
Air	2.46	2.65	2.65	2.66	2.78	2.78	2.79	2.85	2.86	2.86
Military use	0.74	0.63	0.63	0.63	0.68	0.68	0.68	0.77	0.77	0.77
Lubricants	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13
Pipeline fuel	0.70	0.67	0.71	0.79	0.69	0.74	0.86	0.68	0.78	0.99
Total	**27.09**	**27.08**	**27.24**	**27.69**	**26.07**	**26.24**	**26.92**	**26.94**	**27.14**	**28.03**

Table D9. Key transportation results, oil and gas resource cases (continued)

Consumption and indicators	2011	2020 Low Oil and Gas Resource	2020 Reference	2020 High Oil and Gas Resource	2030 Low Oil and Gas Resource	2030 Reference	2030 High Oil and Gas Resource	2040 Low Oil and Gas Resource	2040 Reference	2040 High Oil and Gas Resource
Energy use by fuel (quadrillion Btu)										
Propane	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09
E85[5]	0.05	0.08	0.08	0.08	0.16	0.16	0.17	0.15	0.17	0.16
Motor gasoline[6]	16.31	14.82	14.88	15.07	13.00	13.06	13.32	12.61	12.64	12.98
Jet fuel[7]	3.01	3.11	3.11	3.12	3.28	3.28	3.28	3.42	3.42	3.42
Distillate fuel oil[8]	5.91	7.25	7.28	7.44	7.64	7.61	7.86	8.12	7.90	8.22
Residual fuel oil	0.82	0.84	0.84	0.85	0.85	0.86	0.87	0.87	0.87	0.89
Other petroleum[9]	0.17	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16
Liquid fuels and other petroleum	26.32	26.31	26.42	26.79	25.16	25.20	25.74	25.41	25.24	25.92
Pipeline fuel natural gas	0.70	0.67	0.71	0.79	0.69	0.74	0.86	0.68	0.78	0.99
Compressed/liquefied natural gas	0.04	0.07	0.08	0.08	0.18	0.26	0.27	0.78	1.05	1.06
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.05	0.04	0.04	0.07	0.07	0.06
Delivered energy	**27.09**	**27.08**	**27.24**	**27.69**	**26.07**	**26.25**	**26.92**	**26.94**	**27.14**	**28.03**
Electricity related losses	0.05	0.06	0.06	0.06	0.09	0.09	0.08	0.13	0.13	0.12
Total	**27.13**	**27.15**	**27.30**	**27.74**	**26.16**	**26.33**	**27.01**	**27.07**	**27.27**	**28.15**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined “on-the-road” estimate for all cars and light trucks.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[7]Includes only kerosene type.
[8]Diesel fuel for on- and off- road use.
[9]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Source: 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). Other 2011 data: Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, “Vehicle Inventory and Use Survey”, EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II – User and Fuel Data), April 2011; EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010-2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWRESOURCE.D012813A, REF2013.D102312A, and HIGHRESOURCE.D021413A.

Table D10. Natural gas supply and disposition, oil import cases
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	2011	2030				2040			
		High Net Imports	Reference	High Oil and Gas Resource	Low/No Net Imports	High Net Imports	Reference	High Oil and Gas Resource	Low/No Net Imports
Henry Hub spot price									
(2011 dollars per million Btu)	3.98	7.12	5.40	3.26	3.34	10.69	7.83	4.32	4.36
(2011 dollars per thousand cubic feet)	4.07	7.28	5.52	3.33	3.41	10.93	8.00	4.42	4.45
Dry gas production[1]	**23.00**	**25.87**	**29.79**	**36.89**	**37.23**	**27.29**	**33.14**	**44.91**	**45.12**
Lower 48 onshore	20.54	21.95	26.26	33.30	33.65	22.69	29.12	40.74	41.03
Associated-dissolved[2]	1.54	1.24	1.43	3.05	3.02	0.93	1.09	2.70	2.67
Non-associated	19.00	20.71	24.83	30.25	30.62	21.76	28.03	38.04	38.36
Tight gas	5.86	5.79	6.67	8.86	8.96	5.97	7.34	10.72	10.78
Shale gas	7.85	10.45	14.17	17.56	17.84	11.32	16.70	23.93	24.18
Coalbed methane	1.71	2.16	1.69	1.51	1.52	2.59	2.11	1.53	1.53
Other	3.58	2.30	2.31	2.32	2.31	1.88	1.87	1.86	1.87
Lower 48 offshore	2.11	2.73	2.34	2.37	2.36	3.41	2.85	2.92	2.85
Associated-dissolved[2]	0.54	0.72	0.60	0.65	0.65	0.90	0.74	0.81	0.79
Non-associated	1.58	2.01	1.73	1.72	1.71	2.52	2.11	2.12	2.06
Alaska	0.35	1.19	1.19	1.22	1.22	1.18	1.18	1.25	1.24
Supplemental natural gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net imports	**1.95**	**-0.78**	**-2.10**	**-3.63**	**-3.60**	**-2.24**	**-3.55**	**-6.70**	**-6.68**
Pipeline[4]	1.67	0.08	-0.67	-1.57	-1.53	-1.10	-2.09	-2.84	-2.82
Liquefied natural gas	0.28	-0.86	-1.43	-2.06	-2.06	-1.14	-1.46	-3.86	-3.86
Total supply	**25.01**	**25.16**	**27.75**	**33.33**	**33.70**	**25.11**	**29.65**	**38.27**	**38.50**
Consumption by sector									
Residential	4.72	4.25	4.36	4.52	4.51	4.00	4.14	4.31	4.34
Commercial	3.16	3.25	3.42	3.71	3.69	3.37	3.60	3.97	3.97
Industrial[5]	6.77	7.66	7.79	8.04	7.94	7.74	7.90	8.14	8.16
Natural-gas-to-liquids heat and power[6]	0.00	0.09	0.21	0.36	0.36	0.11	0.33	1.01	0.93
Natural gas to liquids production[7]	0.00	0.10	0.22	0.39	0.39	0.12	0.35	1.10	1.01
Electric power[8]	7.60	7.11	8.89	12.89	12.83	6.02	9.50	14.78	14.78
Transportation[9]	0.04	0.36	0.26	0.27	0.70	1.29	1.04	1.04	1.26
Pipeline fuel	0.68	0.68	0.73	0.85	0.85	0.67	0.76	0.97	0.97
Lease and plant fuel[10]	1.39	1.48	1.70	2.12	2.18	1.66	1.93	2.79	2.83
Total	**24.37**	**24.98**	**27.57**	**33.14**	**33.46**	**25.00**	**29.54**	**38.11**	**38.26**
Discrepancy[11]	0.64	0.18	0.18	0.19	0.24	0.11	0.12	0.16	0.24
Lower 48 end of year dry reserves[1]	**298.96**	**321.40**	**350.65**	**435.34**	**435.38**	**329.61**	**359.97**	**450.88**	**450.65**

[1]Marketed production (wet) minus extraction losses.
[2]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[7]Includes any natural gas converted into liquid fuel.
[8]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[9]Natural gas used as a vehicle fuel.
[10]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[11]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2011 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 supply values; lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2011 consumption based on: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 natural gas price at Henry Hub based on daily spot prices published in Natural Gas Intelligence. **Projections:** EIA, AEO2013 National Energy Modeling System runs HIGHIMPORT.D012813A, REF2013.D102312A, HIGHRESOURCE.D021413A, and LOWIMPORT.D021113B.

Table D11. Liquid fuels supply and disposition, oil import cases
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2011	2030 High Net Imports	2030 Reference	2030 High Oil and Gas Resource	2030 Low/No Net Imports	2040 High Net Imports	2040 Reference	2040 High Oil and Gas Resource	2040 Low/No Net Imports
Crude oil prices (2011 dollars per barrel)									
Brent spot	111.26	135.83	130.47	117.09	111.04	170.69	162.68	143.97	133.95
West Texas Intermediate spot	94.86	133.75	128.47	115.30	109.33	168.59	160.68	142.20	132.30
Imported crude oil[1]	102.65	129.57	125.64	112.93	107.01	161.59	154.96	136.97	127.64
Crude oil supply									
Domestic production[2]	5.67	6.04	6.30	9.96	9.92	5.90	6.13	10.24	10.15
Alaska	0.57	0.44	0.38	0.69	0.69	0.38	0.41	0.89	0.91
Lower 48 States	5.10	5.60	5.92	9.27	9.23	5.51	5.72	9.35	9.25
Net imports	8.89	8.80	7.36	3.74	3.15	9.28	7.57	3.09	3.29
Gross imports	8.94	8.80	7.36	3.74	3.15	9.28	7.57	3.09	3.29
Exports	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other crude oil supply[3]	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude oil supply	**14.81**	**14.84**	**13.66**	**13.70**	**13.06**	**15.18**	**13.70**	**13.33**	**13.45**
Other petroleum supply	**3.02**	**3.74**	**3.82**	**4.30**	**2.99**	**3.36**	**3.29**	**3.96**	**1.11**
Natural gas plant liquids	2.22	2.47	2.90	4.69	4.70	2.43	2.92	5.02	5.00
Net product imports	-0.30	0.11	-0.08	-1.22	-2.41	-0.32	-0.67	-1.82	-4.64
Gross refined product imports[4]	1.15	1.71	1.53	1.36	1.38	1.69	1.42	1.30	1.33
Unfinished oil imports	0.69	0.51	0.51	0.51	0.51	0.45	0.45	0.45	0.45
Blending component imports	0.72	0.56	0.54	0.45	0.45	0.48	0.40	0.37	0.37
Exports	2.86	2.67	2.67	3.53	4.75	2.94	2.94	3.94	6.79
Refinery processing gain[5]	1.08	1.16	1.00	0.82	0.70	1.25	1.03	0.77	0.75
Product stock withdrawal	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**1.09**	**1.62**	**1.58**	**1.60**	**1.60**	**2.01**	**1.97**	**2.25**	**2.25**
Supply from renewable sources	0.90	1.23	1.14	1.16	1.17	1.57	1.43	1.38	1.44
Ethanol	0.84	1.09	0.99	1.02	1.03	1.13	0.97	0.99	1.01
Domestic production	0.91	1.01	0.95	0.98	0.97	1.01	0.89	0.93	0.95
Net imports	-0.07	0.08	0.04	0.04	0.06	0.12	0.08	0.06	0.06
Biodiesel	0.06	0.08	0.08	0.08	0.07	0.08	0.08	0.08	0.07
Domestic production	0.06	0.07	0.07	0.07	0.06	0.07	0.07	0.07	0.06
Net imports	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other biomass-derived liquids[6]	0.00	0.06	0.06	0.06	0.07	0.36	0.38	0.32	0.36
Liquids from gas	0.00	0.05	0.13	0.22	0.22	0.07	0.20	0.62	0.57
Liquids from coal	0.00	0.04	0.04	0.00	0.00	0.06	0.06	0.04	0.04
Other[7]	0.18	0.30	0.28	0.22	0.21	0.31	0.28	0.20	0.21
Total primary supply[8]	**18.92**	**20.20**	**19.06**	**19.59**	**17.65**	**20.55**	**18.96**	**19.55**	**16.81**
Net import share of product supplied (percent)	45.0	44.6	38.5	13.1	4.6	44.3	36.9	6.9	-7.6
Net expenditures for imports of crude oil and petroleum products (billion 2011 dollars)	362.66	421.73	342.67	158.79	127.58	553.11	433.65	159.39	158.09
Lower 48 end of year reserves[2] (billion barrels)	**21.36**	**24.19**	**24.92**	**31.36**	**31.32**	**26.06**	**26.72**	**32.75**	**32.55**

Table D11. Liquid fuels supply and disposition, oil import cases (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2011	2030 High Net Imports	2030 Reference	2030 High Oil and Gas Resource	2030 Low/No Net Imports	2040 High Net Imports	2040 Reference	2040 High Oil and Gas Resource	2040 Low/No Net Imports
Refined petroleum product prices to the transportation sector (2011 dollars per gallon)									
Propane	2.22	2.35	2.26	1.94	1.94	2.52	2.44	2.24	2.18
Ethanol (E85)[9]	2.42	2.95	2.57	2.35	2.44	3.81	2.92	2.74	2.72
Ethanol wholesale price	2.54	2.67	2.28	2.27	2.56	3.13	2.48	2.27	2.38
Motor gasoline[10]	3.45	3.85	3.67	3.39	3.32	4.64	4.32	3.93	3.68
Jet fuel[11]	3.04	3.68	3.51	3.16	3.04	4.50	4.19	3.71	3.53
Distillate fuel oil[12]	3.58	4.36	4.22	3.94	3.87	5.16	4.94	4.47	4.27
Residual fuel oil	2.67	2.83	2.75	2.46	2.35	3.55	3.36	2.98	2.80
Residual fuel oil (2011 dollars per barrel)	112.11	118.76	115.30	103.28	98.84	149.01	141.16	125.08	117.71

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[4]Includes other hydrocarbons and alcohol.
[5]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[6]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[7]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[8]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[9]E85 refers to a blend of 85 pecent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[11]Includes only kerosene-type.
[12]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 crude oil spot prices: Thomson Reuters. 2011 transportation sector prices based on: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report". 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2011 wholesale ethanol prices derived from Bloomberg U.S. average rack price. Other 2011 data: EIA, Petroleum Supply Annual 2011, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs HIGHIMPORT.D012813A, REF2013.D102312A, HIGHRESOURCE.D021413A, and LOWIMPORT.D021113B.

Table D12. Key transportation results, oil import cases

Consumption and indicators	2011	2030				2040			
		High Net Imports	Reference	High Oil and Gas Resource	Low/No Net Imports	High Net Imports	Reference	High Oil and Gas Resource	Low/No Net Imports
Level of travel									
(billion vehicle miles traveled)									
Light-duty vehicles less than 8,501 pounds	2,629	3,257	3,323	3,372	2,753	3,607	3,719	3,775	2,761
Commercial light trucks[1]	65	93	94	96	90	109	110	112	103
Freight trucks greater than 10,000 pounds	240	369	371	385	385	437	438	454	455
(billion seat miles available)									
Air	982	1,177	1,177	1,177	1,177	1,274	1,274	1,274	1,274
(billion ton miles traveled)									
Rail	1,557	1,910	1,910	1,772	1,784	1,997	2,017	1,947	1,966
Domestic shipping	514	570	578	737	735	582	591	773	769
Energy efficiency indicators									
(miles per gallon)									
Tested new light-duty vehicle[2]	31.5	38.8	48.1	47.7	51.6	39.8	49.0	48.5	57.6
New car[2]	36.4	44.4	55.6	55.5	60.5	45.5	56.1	55.9	66.4
New light truck[2]	27.3	32.7	40.3	40.1	43.5	33.2	40.4	40.1	48.1
On-road new light-duty vehicle[3]	25.5	31.4	38.9	38.6	41.7	32.2	39.7	39.3	46.6
New car[3]	29.8	36.3	45.4	45.3	49.4	37.1	45.8	45.7	54.2
New light truck[3]	21.8	26.2	32.3	32.1	34.8	26.6	32.3	32.1	38.5
Light-duty stock[4]	20.6	27.5	31.3	31.2	31.7	29.8	36.1	35.8	39.1
New commercial light truck[1]	18.1	20.5	24.1	24.0	24.9	20.7	24.2	24.0	26.9
Stock commercial light truck[1]	14.9	19.8	22.2	22.1	22.4	20.6	24.1	23.9	25.7
Freight truck	6.7	7.5	8.0	8.0	8.4	7.6	8.2	8.1	8.7
(seat miles per gallon)									
Aircraft	62.3	66.0	67.0	67.0	68.1	69.3	71.5	71.5	74.6
(ton miles per thousand Btu)									
Rail	3.4	3.4	3.5	3.5	3.6	3.4	3.5	3.5	3.7
Domestic shipping	2.4	2.4	2.5	2.5	2.6	2.4	2.6	2.6	2.7
Energy use by mode (quadrillion Btu)									
Light-duty vehicles	15.56	14.29	12.77	13.02	10.41	14.64	12.43	12.72	8.47
Commercial light trucks[1]	0.54	0.59	0.53	0.54	0.50	0.66	0.57	0.58	0.50
Bus transportation	0.25	0.29	0.29	0.29	0.29	0.32	0.32	0.32	0.32
Freight trucks	4.95	6.79	6.39	6.64	6.28	7.80	7.31	7.62	7.19
Rail, passenger	0.05	0.06	0.06	0.06	0.06	0.07	0.06	0.06	0.06
Rail, freight	0.45	0.55	0.54	0.50	0.51	0.58	0.57	0.55	0.55
Shipping, domestic	0.21	0.24	0.23	0.30	0.29	0.24	0.23	0.30	0.29
Shipping, international	0.80	0.83	0.82	0.82	0.82	0.84	0.84	0.84	0.83
Recreational boats	0.24	0.27	0.28	0.28	0.28	0.28	0.29	0.30	0.30
Air	2.46	2.82	2.78	2.79	2.75	2.94	2.86	2.86	2.75
Military use	0.74	0.68	0.68	0.68	0.68	0.77	0.77	0.77	0.77
Lubricants	0.13	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.13
Pipeline fuel	0.70	0.69	0.74	0.86	0.87	0.69	0.78	0.99	0.99
Total	**27.09**	**28.23**	**26.24**	**26.92**	**23.88**	**29.95**	**27.14**	**28.03**	**23.16**

Table D12. Key transportation results, oil import cases (continued)

Consumption and indicators	2011	2030				2040			
		High Net Imports	Reference	High Oil and Gas Resource	Low/No Net Imports	High Net Imports	Reference	High Oil and Gas Resource	Low/No Net Imports
Energy use by fuel (quadrillion Btu)									
Propane	0.06	0.08	0.07	0.08	0.07	0.10	0.08	0.09	0.07
E85[5]	0.05	0.15	0.16	0.17	0.43	0.20	0.17	0.16	0.65
Motor gasoline[6]	16.31	14.57	13.06	13.32	10.53	14.77	12.64	12.98	8.31
Jet fuel[7]	3.01	3.32	3.28	3.28	3.24	3.50	3.42	3.42	3.32
Distillate fuel oil[8]	5.91	8.00	7.61	7.86	6.89	8.26	7.90	8.22	7.34
Residual fuel oil	0.82	0.86	0.86	0.87	0.87	0.88	0.87	0.89	0.88
Other petroleum[9]	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Liquid fuels subtotal	26.32	27.13	25.20	25.74	22.20	27.87	25.24	25.92	20.73
Pipeline fuel natural gas	0.70	0.69	0.74	0.86	0.87	0.69	0.78	0.99	0.99
Compressed / liquefied natural gas	0.04	0.36	0.26	0.27	0.71	1.31	1.05	1.06	1.29
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.04	0.04	0.04	0.09	0.07	0.07	0.06	0.15
Delivered energy	**27.09**	**28.23**	**26.25**	**26.92**	**23.88**	**29.95**	**27.14**	**28.03**	**23.16**
Electricity related losses	0.05	0.09	0.09	0.08	0.18	0.14	0.13	0.12	0.26
Total	**27.13**	**28.32**	**26.33**	**27.01**	**24.05**	**30.09**	**27.27**	**28.15**	**23.42**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined "on-the-road" estimate for all cars and light trucks.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[7]Includes only kerosene type.
[8]Diesel fuel for on- and off- road use.
[9]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Source: 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). Other 2011 data: Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey", EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II – User and Fuel Data), April 2011; EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010-2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2013 National Energy Modeling System runs HIGHIMPORT.D012813A, REF2013.D102312A, HIGHRESOURCE.D021413A, and LOWIMPORT.D021113B.

Table D13. Key results for No Greenhouse Gas Concern case
(million short tons per year, unless otherwise noted)

Supply, disposition, prices, and electricity generating capacity additions	2011	2020		2030		2040	
		Reference	No GHG Concern	Reference	No GHG Concern	Reference	No GHG Concern
Production[1]	1,096	1,071	1,080	1,153	1,149	1,167	1,211
Appalachia	337	288	290	295	298	283	284
Interior	171	198	198	212	213	226	248
West	588	585	592	646	638	658	679
Waste coal supplied[2]	13	19	19	20	20	27	29
Net imports[3]	-96	-125	-125	-139	-133	-123	-111
Total supply[4]	**1,012**	**966**	**974**	**1,034**	**1,036**	**1,071**	**1,128**
Consumption by sector							
Residential and commercial	3	3	3	3	3	3	3
Coke plants	21	23	23	20	20	18	18
Other industrial[5]	46	50	50	50	50	52	52
Coal-to-liquids heat and power	0	0	0	5	2	8	4
Coal-to-liquids liquids production	0	0	0	4	2	6	3
Electric power[6]	929	890	898	953	960	984	1,048
Total coal consumption	**999**	**966**	**974**	**1,034**	**1,036**	**1,071**	**1,128**
Average minemouth price[7]							
(2011 dollars per short ton)	41.16	49.26	49.13	55.64	55.83	61.28	61.15
(2011 dollars per million Btu)	2.04	2.45	2.45	2.79	2.79	3.08	3.09
Delivered prices[8] (2011 dollars per short ton)							
Coke plants	184.44	229.19	228.99	264.13	263.97	290.84	290.85
Other industrial[5]	70.68	72.44	72.48	78.25	78.24	85.63	86.67
Coal to liquids	- -	- -	- -	47.71	55.16	55.60	52.25
Electric power[6]							
(2011 dollars per short ton)	46.38	47.91	47.86	54.37	54.44	60.77	61.34
(2011 dollars per million Btu)	2.38	2.52	2.51	2.87	2.87	3.20	3.24
Average	**50.64**	**53.47**	**53.39**	**59.53**	**59.64**	**65.70**	**66.04**
Exports[9]	148.86	168.73	168.93	177.76	177.62	176.05	173.77
Cumulative electricity generating capacity additions (gigawatts)[10]							
Coal	0.0	6.4	6.4	7.2	8.4	8.8	25.7
Conventional	0.0	4.9	4.9	4.9	6.5	6.1	23.6
Advanced without sequestration	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Advanced with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9
End-use generators[11]	0.0	0.0	0.0	0.8	0.4	1.3	0.7
Petroleum	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Natural gas	0.0	38.1	37.4	120.2	117.1	215.2	209.4
Nuclear / uranium	0.0	5.5	5.5	5.5	5.5	11.0	6.1
Renewables[12]	0.0	37.1	37.4	48.8	47.8	104.3	84.8
Other	0.0	0.2	0.2	0.2	0.2	0.2	0.2
Total	**0.0**	**87.6**	**87.2**	**182.2**	**179.2**	**339.9**	**326.4**
Liquids from coal (million barrels per day)	0.00	0.00	0.00	0.04	0.02	0.06	0.03

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship prices.
[9]Free-alongside-ship price at U.S. port of exit.
[10]Cumulative additions after December 31, 2011. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012); EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012); and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. **Projections:** EIA, AEO2013 National Energy Modeling System runs REF2013.D102312A and NOGHGCONCERN.D110912A.

Table D14. Key results for coal cost cases
(million short tons per year, unless otherwise noted)

Supply, disposition, prices, electricity generating capacity additions, and costs	2011	2020			2040			Annual growth 2011-2040 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	1,096	1,129	1,071	985	1,363	1,167	838	0.8%	0.2%	-0.9%
Appalachia	337	300	288	276	345	283	243	0.1%	-0.6%	-1.1%
Interior	171	210	198	185	253	226	191	1.4%	1.0%	0.4%
West	588	619	585	525	764	658	404	0.9%	0.4%	-1.3%
Waste coal supplied[2]	13	16	19	20	13	27	47	0.1%	2.7%	4.6%
Net imports[3]	-96	-129	-125	-123	-206	-123	-78	2.7%	0.9%	-0.7%
Total supply[4]	**1,012**	**1,016**	**966**	**882**	**1,170**	**1,071**	**806**	**0.5%**	**0.2%**	**-0.8%**
Consumption by sector										
Residential and commercial	3	3	3	3	3	3	2	-0.2%	-0.3%	-0.4%
Coke plants	21	23	23	23	18	18	17	-0.6%	-0.7%	-0.8%
Other industrial[5]	46	50	50	50	52	52	51	0.4%	0.4%	0.3%
Coal-to-liquids heat and power	0	5	0	0	13	8	0	- -	- -	- -
Coal-to-liquids liquids production	0	4	0	0	10	6	0	- -	- -	- -
Electric power[6]	929	932	890	807	1,075	984	735	0.5%	0.2%	-0.8%
Total coal use	**999**	**1,016**	**966**	**882**	**1,170**	**1,071**	**807**	**0.5%**	**0.2%**	**-0.7%**
Average minemouth price[7]										
(2011 dollars per short ton)	41.16	40.89	49.26	61.11	33.90	61.28	128.09	-0.7%	1.4%	4.0%
(2011 dollars per million Btu)	2.04	2.04	2.45	3.02	1.70	3.08	6.20	-0.6%	1.4%	3.9%
Delivered prices[8] (2011 dollars per short ton)										
Coke plants	184.44	198.35	229.19	264.37	178.75	290.84	475.91	-0.1%	1.6%	3.3%
Other industrial[5]	70.68	63.21	72.44	83.01	53.10	85.63	145.06	-1.0%	0.7%	2.5%
Coal to liquids	- -	29.33	- -	- -	27.23	55.60	107.69	- -	- -	- -
Electric power[6]										
(2011 dollars per short ton)	46.38	41.46	47.91	56.00	35.63	60.77	110.99	-0.9%	0.9%	3.1%
(2011 dollars per million Btu)	2.38	2.17	2.52	2.93	1.88	3.20	5.68	-0.8%	1.0%	3.0%
Average	**50.64**	**46.00**	**53.47**	**62.86**	**38.45**	**65.70**	**120.95**	**-0.9%**	**0.9%**	**3.0%**
Exports[9]	148.86	147.66	168.73	194.63	117.53	176.05	317.96	-0.8%	0.6%	2.7%
Cumulative electricity generating capacity additions (gigawatts)[10]										
Coal	0.0	7.1	6.4	6.4	16.2	8.8	6.5	- -	- -	- -
Conventional	0.0	4.9	4.9	4.9	12.9	6.1	4.9	- -	- -	- -
Advanced without sequestration	0.0	0.6	0.6	0.6	0.6	0.6	0.6	- -	- -	- -
Advanced with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9	- -	- -	- -
End-use generators[11]	0.0	0.7	0.0	0.0	1.8	1.3	0.1	- -	- -	- -
Petroleum	0.0	0.3	0.3	0.3	0.3	0.3	0.3	- -	- -	- -
Natural gas	0.0	37.0	38.1	37.3	210.7	215.2	221.8	- -	- -	- -
Nuclear / uranium	0.0	5.5	5.5	5.5	8.6	11.0	8.7	- -	- -	- -
Renewables[12]	0.0	38.4	37.1	38.2	111.4	104.3	90.3	- -	- -	- -
Other	0.0	0.2	0.2	0.2	0.2	0.2	0.2	- -	- -	- -
Total	**0.0**	**88.5**	**87.6**	**87.9**	**347.3**	**339.9**	**327.7**	- -	- -	- -
Liquids from coal (million barrels per day)	0.00	0.03	0.00	0.00	0.09	0.06	0.00	- -	- -	- -

Table D14. Key results for coal cost cases (continued)
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	2011	2020			2040			Annual growth 2011-2040 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Cost indices										
(constant dollar index, 2011=1.000)										
Transportation rate multipliers										
Eastern railroads	1.000	0.950	1.028	1.070	0.750	1.003	1.240	-1.0%	0.0%	0.7%
Western railroads	1.000	0.920	0.989	1.060	0.760	1.013	1.270	-0.9%	0.0%	0.8%
Mine equipment costs										
Underground	1.000	0.923	1.000	1.083	0.755	1.000	1.321	-1.0%	0.0%	1.0%
Surface	1.000	0.923	1.000	1.083	0.755	1.000	1.321	-1.0%	0.0%	1.0%
Other mine supply costs										
East of the Mississippi: all mines	1.000	0.923	1.000	1.083	0.755	1.000	1.321	-1.0%	0.0%	1.0%
West of the Mississippi: underground	1.000	0.923	1.000	1.083	0.755	1.000	1.321	-1.0%	0.0%	1.0%
West of the Mississippi: surface	1.000	0.923	1.000	1.083	0.755	1.000	1.321	-1.0%	0.0%	1.0%
Coal mining labor productivity (short tons per miner per hour)	5.19	5.45	4.43	3.49	6.68	3.47	1.44	0.9%	-1.4%	-4.3%
Average coal miner wage (2011 dollars per year)	81,258	87,721	95,199	102,572	80,105	105,676	138,365	0.0%	0.9%	1.9%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal to liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship prices.
[9]Free-alongside-ship price at U.S. port of exit.
[10]Cumulative additions after December 31, 2011. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2011 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012); EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012); U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. **Projections:** EIA, AEO2013 National Energy Modeling System runs LCCST13.D112112A, REF2013.D102312A, and HCCST13.D112112A.

Appendix E

NEMS overview and brief description of cases

The National Energy Modeling System

Projections in the *Annual Energy Outlook 2013 (AEO2013)* are generated using the National Energy Modeling System (NEMS) [*148*], developed and maintained by the Office of Energy Analysis of the U.S. Energy Information Administration (EIA). In addition to its use in developing the *Annual Energy Outlook (AEO)* projections, NEMS is also used to complete analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other Federal agencies. NEMS is also used by other nongovernment groups, such as the Electric Power Research Institute, Duke University, and Georgia Institute of Technology. In addition, the *AEO* projections are used by analysts and planners in other government agencies and nongovernment organizations.

The projections in NEMS are developed with the use of a market-based approach, subject to regulations and standards. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS extends to 2040. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the 9 Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation for electricity; and 9 refining regions that are a subset of the 5 Petroleum Administration for Defense Districts (PADDs).

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users. The information flows also include such areas as economic activity, domestic production, and international petroleum supply. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached for each year from 2012 through 2040. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all energy-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and mercury from the electricity generation sector.

The version of NEMS used for *AEO2013* generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of September 30, 2012, as discussed in the "Legislation and regulations" section of the *AEO*. The potential impacts of proposed federal and state legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. Many of the pending provisions, however, are examined in alternative cases included in *AEO2013* or in other analysis completed by EIA.

In general, the historical data presented with the *AEO2013* projections are based on EIA's *Annual Energy Review 2011*, published in September 2012 [*149*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2011. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2013* appendix tables indicate the definitions and sources of historical data.

Where possible, the *AEO2013* projections for 2012 and 2013 incorporate short-term projections from EIA's September 2012 *Short-Term Energy Outlook (STEO)* [*150*]. EIA's views regarding energy use over the 2012 through 2014 period are reported in monthly updates of the *STEO* [*151*], which should be considered to supersede information reported for those years in *AEO2013*.

Component modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing prices or expenditures for energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules and receives energy-related indicators from the NEMS energy components as part of the macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, sales of new light-duty vehicles (LDVs), interest rates, and employment. Key energy indicators fed back to the MAM include aggregate energy prices and quantities. The MAM uses the following models from IHS

Global Insight: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers, and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Energy Module

The International Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum and other liquids production and consumption, by year, to project the interaction of U.S. and international petroleum and other liquids markets. The IEM provides a world crude-like liquids supply curve and generates a worldwide oil supply/demand balance for each year of the projection period. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international petroleum and other liquids supply and demand, current investment trends in exploration and development, and long-term resource economics by country and territory. The oil production estimates include both petroleum and other liquids supply recovery technologies. The IEM also provides, for each year of the projection period, endogenous and exogenous assumptions for petroleum products for import and export in the United States. In interacting with the rest of NEMS, the IEM changes Brent and West Texas Intermediate (WTI) prices in response to changes in expected production and consumption of crude oil and other liquids in the United States.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by Census division, housing type, and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and changes in the housing stock. The Commercial Demand Module projects energy consumption in the commercial sector by Census division, building type, and category of end use, based on delivered prices of energy, the menu of available equipment, availability of renewable sources of energy, and changes in commercial floorspace.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, representations of renewable energy technologies, and the effects of both building shell and appliance standards. The modules also include projections of distributed generation. The Commercial Demand Module also incorporates combined heat and power (CHP) technology. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on a 30-year historical trend and on state-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in new construction and remodeling.

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, as well as the consumption of feedstocks and raw materials in each of 21 industry groups, subject to the delivered prices of energy and macroeconomic estimates of employment and the value of shipments for each industry. As noted in the description of the MAM, the representation of industrial activity in NEMS is based on the NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Seven of eight energy-intensive manufacturing industries are modeled in the IDM, including energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Energy demand for petroleum and other liquids refining (the eighth energy-intensive manufacturing industry) is modeled in the Liquid Fuels Market Module (LFMM) as described below, but the projected consumption is reported under the industrial totals.

There are several updates and upgrades in the representations of select industries. *AEO2013* includes an upgraded representation for the aluminum industry. Instead of assuming that technological development for a particular process occurs on a predetermined or exogenous path based on engineering judgment, these upgrades allow IDM technological change to be modeled endogenously, while using more detailed process representation. The upgrade allows for explicit technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. The combined cement and lime industry was upgraded in the *Annual Energy Outlook 2012 (AEO2012).* For subsequent *AEO*s other energy-intensive industries will be similarly upgraded.

The bulk chemicals model has been enhanced in several respects: baseline natural gas liquids feedstock data were aligned with Manufacturing Energy Consumption Survey 2006 data; an updated propane pricing mechanism reflecting natural gas price influences was used to allow for price competition between liquefied petroleum gas feedstock and petroleum-based (naphtha) feedstock; and propylene supplied by the refining industry is now specifically accounted for in the LFMM.

Nonmanufacturing models were significantly revised as well. The construction and mining models were augmented to better reflect NEMS assumptions regarding energy efficiencies in (off-road) vehicles and buildings, as well as coal, oil, and natural gas extraction productivity. The agriculture model was similarly augmented in *AEO2012*. The IDM also includes a generalized representation of CHP. The methodology for CHP systems simulates the utilization of installed CHP systems based on historical utilization rates and is driven by end-use electricity demand. To evaluate the economic benefits of additional CHP capacity, the model also includes an appraisal incorporating historical capacity factors and regional acceptance rates for new CHP facilities.

There are also enhancements to the IDM to account for regulatory changes. This includes the State of California's Global Warming Solutions Act (AB 32) that allows for representation of a cap-and-trade program developed as part of California's greenhouse gas (GHG) emissions reduction goals for 2020. Another regulatory update is included for the handling of National Emissions Standards for Hazardous Air Pollutants for industrial boilers, to address the maximum degree of emission reduction using maximum achievable control technology (MACT).

Transportation Demand Module

The Transportation Demand Module projects consumption of energy by mode and fuel—including petroleum products, electricity, methanol, ethanol, compressed natural gas (CNG), liquefied natural gas (LNG), and hydrogen—in the transportation sector, subject to delivered energy prices, macroeconomic variables such as GDP, and other factors such as technology adoption. The Transportation Demand Module includes legislation and regulations, such as the Energy Policy Act of 2005 (EPACT2005), the Energy Improvement and Extension Act of 2008 (EIEA2008), and the American Recovery and Reinvestment Act of 2009 (ARRA2009), which contain tax credits for the purchase of alternatively fueled vehicles. Representations of LDV corporate average fuel economy (CAFE) and GHG emissions standards, HDV fuel consumption and GHG emissions standards, and biofuels consumption reflect standards enacted by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA), as well as provisions in the Energy Independence and Security Act of 2007 (EISA2007).

The air transportation component of the Transportation Demand Module represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets. For passenger travel and air freight shipments, the module represents regional fuel use and travel demand for three aircraft types: regional, narrow-body, and wide-body. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

The Transportation Demand Module projects energy consumption for freight and passenger rail and marine vessels by mode and fuel, subject to macroeconomic variables such as the value and type of industrial shipments.

Electricity Market Module

There are three primary submodules of the Electricity Market Module (EMM)—capacity planning, fuel dispatching, and finance and pricing. The capacity expansion submodule uses the stock of existing generation capacity, known environmental regulations, the expected cost and performance of future generation capacity, expected fuel prices, expected financial parameters, and expected electricity demand to project the optimal mix of new generation capacity that should be added in future years. The fuel dispatching submodule uses the existing stock of generation equipment types, their operation and maintenance costs and performance, fuel prices to the electricity sector, electricity demand, and all applicable environmental regulations to determine the least-cost way to meet that demand. The submodule also determines transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 are explicitly represented in the capacity expansion and dispatch decisions. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in *AEO2013*. The *AEO2013* Reference case also imposes a limit on CO_2 emissions for specific covered sectors, including the electric power sector, in California, as represented in California's AB 32. The *AEO2013* Reference case leaves the Clean Air Interstate Rule (CAIR) in effect after the court vacated the Cross-State Air Pollution Rule (CSAPR) in August 2012. CAIR incorporates a cap and trade program for annual emissions of SO_2 and annual and seasonal emissions of NO_X from fossil power plants. Reductions in hazardous air pollutant emissions from coal- and oil-fired steam electric power plants also are reflected through the inclusion of the Mercury and Air Toxics Standards for power plants, finalized by the EPA on December 16, 2011.

Although currently there is no Federal legislation in place that restricts GHG emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the *AEO2013* Reference case through a 3-percentage-point increase in the cost of capital, when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL) plants without carbon capture and storage (CCS), and pollution control retrofits.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and both onshore and offshore wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-percent ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30 percent for solar energy systems installed before January 1, 2017. The extension of the credit to individual homeowners under EIEA2008 is reflected in the Residential and Commercial Demand Modules.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented, based on the laws in effect on October 31, 2012. They provide a credit of up to 2.2 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2013*, new wind plants coming on line before January 1, 2013, are eligible to receive the PTC; other eligible plants must be in service before January 1, 2014. The law was subsequently amended to extend the PTC for wind. The impact of this amendment is considered in the American Taxpayer Relief Act of 2012 case discussed in the "Issues in focus" section of *AEO2013*. Furthermore, eligible plants of any type will qualify if construction begins prior to the expiration date, regardless of when the plant enters commercial service. This change was made after the completion of *AEO2013* and is not reflected in the analysis. As part of ARRA2009, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2013* also accounts for new renewable energy capacity resulting from state renewable portfolio standard programs, mandates, and goals, as described in *Assumptions to the Annual Energy Outlook 2013* [*152*].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply—onshore, offshore, and Alaska—by all production techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production activities are modeled for 12 supply regions, including 6 onshore, 3 offshore, and 3 Alaskan regions.

The Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas at the play level. Crude oil resources include conventional, structurally reservoired resources as well as highly fractured continuous zones, such as the Austin chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as CO_2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources include high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic crude oil production quantities are used as inputs to the LFMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 lower 48 U.S. demand regions. The 12 lower 48 regions align with the 9 Census divisions, with three subdivided, and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. An algorithm is included to project the addition of CNG retail fueling capability. The module also accounts for foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, as well as LNG imports and exports.

Liquid Fuels Market Module

The LFMM projects prices of petroleum products, crude oil and product import activity, as well as domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, gas-to-liquids (GTL), and coal-and-biomass-to-liquids (CBTL). Costs, performance, and first dates of commercial availability for the advanced liquid fuels technologies [*153*] are reviewed and updated annually.

The module represents refining activities in eight domestic U.S. regions, and a new Maritime Canada/Caribbean refining region (created to represent short-haul international refineries that predominantly serve U.S. markets). In order to better represent policy, import/export patterns, and biofuels production, the eight U.S. regions were defined by subdividing three of the five U.S. PADDs. All nine refining regions are defined below.

Region 1. PADD I – East Coast

Region 2. PADD II – Interior

Region 3. PADD II – Great Lakes

Region 4. PADD III – Gulf Coast

Region 5. PADD III – Interior

Region 6. PADD IV – Mountain

Region 7. PADD V – California

Region 8. PADD V – Other

Region 9. Maritime Canada/Caribbean

The capacity expansion submodule uses the stock of existing generation capacity, the cost and performance of future generation capacity, expected fuel prices, expected financial parameters, expected electricity demand, and expected environmental regulations to project the optimal mix of new generation capacity that should be added in future years.

The LFMM models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. Fuel ethanol and biodiesel are included in the LFMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent by volume, 15 percent by volume (E15) in states that lack explicit language capping ethanol volume or oxygen content, and up to 85 percent by volume (E85) for use in flex-fuel vehicles. Crude and refinery product imports are represented by supply curves defined by the NEMS IEM. Products also can be imported from refining region 9 (Maritime Canada/Caribbean). Refinery product exports are provided by the IEM.

Capacity expansion of refinery process units and nonpetroleum liquid fuels production facilities is also modeled in the LFMM. The model uses current liquid fuels production capacity, the cost and performance of each production unit, expected fuel and feedstock costs, expected financial parameters, expected liquid fuels demand, and relevant environmental policies to project the optimal mix of new capacity that should be added in the future.

The LFMM includes representation of the renewable fuels standard (RFS) specified in EISA2007, which mandates the use of 36 billion gallons of ethanol equivalent renewable fuel by 2022. Both domestic and imported biofuels count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Starch-based ethanol plants are numerous (more than 190 are now in operation, with a total maximum sustainable nameplate capacity of more than 14 billion gallons annually), and they are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation. Ethanol from advanced feedstocks—produced at ethanol refineries that ferment and distill grains other than corn, and reduce GHG emissions by at least 50 percent—is also a new technology modeled in the LFMM.

Fuels produced by Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the LFMM, based on their economics relative to competing feedstocks and products. The five processes modeled are CTL, CBTL, GTL, BTL, and pyrolysis.

Two California-specific policies are also represented in the LFMM: the low carbon fuel standard (LCFS) and the AB 32 cap-and-trade program. The LCFS requires the carbon intensity (amount of greenhouse gases per unit of energy) of transportation fuels sold for use in California to decrease according to a schedule published by the California Air Resources Board. California's AB 32 cap-and-trade program is established to help California achieve its goal of reducing CO_2 emissions to 1990 levels by 2020. Working with other NEMS modules (IDM, EMM, and Emissions Policy Module), the LFMM provides emissions allowances and actual emissions of CO_2 from California refineries, and NEMS provides the mechanism (carbon price) to trade allowances such that the total CO_2 emissions cap is met.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 41 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves respond to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by region and sector; environmental restrictions; and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes production and transportation costs while meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 16 demand regions.

Annual Energy Outlook 2013 cases

Table E1 provides a summary of the cases produced as part of *AEO2013*. For each case, the table gives the name used in *AEO2013*, a brief description of the major assumptions underlying the projections, and a reference to the pages in the body of the report and in this appendix where the case is discussed. The text sections following Table E1 describe the various cases in more detail. The Reference case assumptions for each sector are described in *Assumptions to the Annual Energy Outlook 2013* [*154*]. Regional results and other details of the projections are available at website www.eia.gov/forecasts/aeo/tables_ref.cfm#supplement.

Macroeconomic growth cases

In addition to the *AEO2013* Reference case, Low Economic Growth and High Economic Growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- In the Reference case, population grows by 0.9 percent per year, nonfarm employment by 1.0 percent per year, and labor productivity by 1.9 percent per year from 2011 to 2040. Economic output as measured by real GDP increases by 2.5 percent per year from 2011 through 2040, and growth in real disposable income per capita averages 1.4 percent per year.
- The Low Economic Growth case assumes lower growth rates for population (0.8 percent per year) and labor productivity (1.4 percent per year), resulting in lower nonfarm employment (0.8 percent per year), higher prices and interest rates, and lower growth in industrial output. In the Low Economic Growth case, economic output as measured by real GDP increases by 1.9 percent per year from 2011 through 2040, and growth in real disposable income per capita averages 1.2 percent per year.
- The High Economic Growth case assumes higher growth rates for population (1.0 percent per year) and labor productivity (2.1 percent per year), resulting in higher nonfarm employment (1.1 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case, and consequently economic output grows at a higher rate (2.9 percent per year) than in the Reference case (2.5 percent). Disposable income per capita grows by 1.6 percent per year, compared with 1.4 percent in the Reference case.

Oil price cases

For *AEO2013*, the benchmark oil price is being re-characterized to represent Brent crude oil instead of WTI crude oil. This change is being made to better reflect the marginal price refineries pay for imported light, sweet crude oil, used to produce petroleum products for consumers. EIA will continue to report the WTI price, as it is a critical reference point to for evaluation of growing production in the mid-continent. EIA will also continue to report the Imported Refiner Acquisition Cost.

The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2013* considers three oil price cases (Reference, Low Oil Price, and High Oil Price) to allow an assessment of alternative views on the future course of oil prices.

The Low and High Oil Price cases reflect a wide range of potential price paths, resulting from variation in demand by countries outside the Organization for Economic Cooperation and Development (OECD) for petroleum and other liquid fuels due to different levels of economic growth. The Low and High Oil Price cases also reflect different assumptions about decisions by members of the Organization of the Petroleum Exporting Countries (OPEC) regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional structurally reservoired oil resources outside the United States.

- In the Reference case, real oil prices (in 2011 dollars) rise from $109 per barrel in 2011 to $163 per barrel in 2040. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's oil production will represent between 40 and 43 percent of the world's total petroleum and other liquids production over the projection period.
- In the Low Oil Price case, crude oil prices are $75 per barrel (2011 dollars) in 2040. The low price results from lower demand for petroleum and other liquid fuels in the non-OECD nations. Lower demand is derived from lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD countries is lower on average relative to the Reference case in each projection year, beginning in 2013. The OECD projections are affected only by the price impact. On the supply side, OPEC countries increase their oil production to obtain a 49-percent share of total world petroleum and other liquids production in 2040, and oil resources outside the United States are more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the Reference case.
- In the High Oil Price case, oil prices reach about $237 per barrel (2011 dollars) in 2040. The high prices result from higher demand for petroleum and other liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD countries is higher on average relative to the Reference case in each projection year, beginning in 2013. The OECD projections are affected only by the price impact. On the supply side, OPEC countries reduce their market share to between 37 and 40 percent, and oil resources outside the United States are less accessible and/or more costly to produce than in the Reference case.

Table E1. Summary of the *AEO2013* cases

Case name	Description	Reference in text	Reference in Appendix E
Reference	Real GDP grows at an average annual rate of 2.5 percent from 2011 to 2040. Crude oil prices rise to about $163 per barrel (2011 dollars) in 2040. Complete projection tables in Appendix A.	--	--
Low Economic Growth	Real GDP grows at an average annual rate of 1.9 percent from 2011 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. 56	p. 214
High Economic Growth	Real GDP grows at an average annual rate of 2.9 percent from 2011 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. 56	p. 214
Low Oil Price	Low prices result from a combination of low demand for petroleum and other liquids in the non-OECD nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. On the supply side, OPEC increases its market share to 49 percent, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $75 per barrel in 2040. Partial projection tables in Appendix C.	p. 31	p. 214
High Oil Price	High prices result from a combination of higher demand for petroleum and other liquids in the non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. Non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Crude oil prices rise to $237 per barrel (2011 dollars) in 2040. Partial projection tables in Appendix C.	p. 31	p. 214
No Sunset	Begins with the Reference case and assumes extension of all existing energy policies and legislation that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards. Partial projection tables in Appendix D.	p. 25	p. 218
Extended Policies	Begins with the No Sunset case and assumes an increase in the capacity limitations on the ITC and extension of the program. The case includes additional rounds of efficiency standards for residential and commercial products, as well as new standards for products not yet covered; adds multiple rounds of national building codes by 2026; and increases LDV fuel economy standards in the transportation sector to 57.7 miles per gallon in 2040. Partial projection tables in Appendix D.	p. 25	p. 218
Electricity: Low Nuclear	Assumes that all nuclear plants are limited to a 60-year life (45 gigawatts of retirements), uprates are limited to the 1.3 gigawatts that have been reported to EIA, and planned additions are the same as in the Reference case. Partial projection tables in Appendix D.	p. 46	p. 219
Electricity: High Nuclear	Assumes that all nuclear plants are life-extended beyond 60 years (except for one announced retirement), and uprates are the same as in the Reference case. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission (NRC) or Atomic Safety and Licensing Board hearing. Partial projection tables in Appendix D.	p. 47	p. 220
Electricity: Small Modular Reactor	Assumes that the characteristics of the new advanced nuclear technology are based on a small modular design rather than the AP1000. Partial projection tables in Appendix D.	p. 47	p. 220
Renewable Fuels: Low Renewable Technology Cost	Costs for new nonhydropower renewable generating technologies are 20 percent lower than Reference case levels through 2040. Capital costs for new BTL technologies and biodiesel production technologies are reduced by 20 percent relative to the Reference case through 2040. Partial projection tables in Appendix D.	p. 193	p. 218

Table E1. Summary of the *AEO2013* cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Oil and Gas: Low Oil and Gas Resource	Estimated ultimate recovery (EUR) per shale gas, tight gas, and tight oil well is 50 percent lower than in the Reference case. Partial projection tables in Appendix D.	p. 33	p. 220
Oil and Gas: High Oil and Gas Resource	Shale gas, tight gas, and tight oil well EURs are 100 percent higher than in the Reference case, and the maximum well spacing is assumed to be 40 acres. Also includes kerogen development, tight oil resources in Alaska, and 50 percent higher undiscovered resources in lower 48 offshore and Alaska than in the Reference case. Partial projection tables in Appendix D.	p. 33	p. 220
Liquids Market: Low/No Net Imports	Uses *AEO2013* Reference case oil price, with assumed greater improvement in vehicle efficiency and lower vehicle technology costs; post-2025 increase in CAFE standards by 1.4 percent through 2040; lower vehicle miles traveled (VMT); expanded market availability of LNG/CNG in heavy-duty trucks, rail, and marine; higher GTL market penetration; optimistic battery case (*AEO2012*) assumptions for electric drivetrain vehicle costs; and greater availability of domestic petroleum supply (consistent with the High Oil and Gas Resource case). Also assumes increased market penetration of biomass pyrolysis oils, CTL, and BTL production. Also, initial assumptions associated with E85 availability and maximum penetration of E15 are set to be more optimistic. Partial projection tables in Appendix D.	p. 33	p. 221
Liquids Market: High Net Imports	Uses *AEO2013* Reference case oil price, with assumed lower improvement in vehicle efficiency (driven by limits on technology improvement and non-enforcement of CAFE standards), higher VMT, no change in LNG/CNG market availability, no change in GTL penetration, no change in biofuel market penetration from the Reference case, and lower availability of domestic petroleum supply (consistent with the Low Oil and Gas Resource case). Partial projection tables in Appendix D.	p. 33	p. 221
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.5 percent per year higher than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates are lower than in the Reference case, falling to about 25 percent below the Reference case in 2040. Partial projection tables in Appendix D.	p. 40	p. 221
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.5 percent per year lower than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates are higher than in the Reference case, ranging between 25 and 32 percent above the Reference case in 2040. Partial projection tables in Appendix D.	p. 40	p. 221
Integrated 2012 Demand Technology	Referred to in the text as "2012 Demand Technology." Assumes that future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2012. Building shell efficiency is held constant at 2012 levels. Energy efficiency of new industrial plant and equipment is held constant at the 2013 level over the projection period. Partial projection tables in Appendix D.	p. 61	p. 217
Integrated Best Available Demand Technology	Referred to in the text as "Best Available Demand Technology." Assumes that all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Residential building shells for new construction are built to the most efficient specifications after 2012, and existing residential shells have twice the improvement of the Reference case. New and existing commercial building shell efficiencies improve 50 percent more than in the Reference case by 2040. Industrial and transportation sector assumptions are the same as in the Reference case. Partial projection tables in Appendix D.	p. 61	p. 217

Table E1. Summary of the *AEO2013* cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Integrated High Demand Technology	Referred to in the text as High Demand Technology. Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Existing residential shell exhibits 50 percent more improvement than in the Reference case after 2012. New and existing commercial building shells are assumed to improve 25 percent more than in the Reference case by 2040. For the industrial sector, assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors. Partial projection tables in Appendix D.	p. 61	p. 217
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy. Partial projection tables in Appendix D.	p. 87	p. 222
GHG10	Applies a price for CO_2 emissions throughout the economy, starting at $10 per metric ton in 2014 and rising by 5 percent per year through 2040. Partial projection tables in Appendix D.	p. 86	p. 222
GHG15	Applies a price for CO_2 emissions throughout the economy, starting at $15 per metric ton in 2014 and rising by 5 percent per year through 2040. Partial projection tables in Appendix D.	p. 86	p. 222
GHG25	Applies a price for CO_2 emissions throughout the economy, starting at $25 per metric ton in 2014 and rising by 5 percent per year through 2040. Partial projection tables in Appendix D.	p. 86	p. 222
GHG10 and Low Gas Prices	Combines GHG10 and High Oil and Gas Resource cases. Partial projection tables in Appendix D.	p. 89	p. 222
GHG15 and Low Gas Prices	Combines GHG15 and High Oil and Gas Resource cases. Partial projection tables in Appendix D.	p. 89	p. 222
GHG25 and Low Gas Prices	Combines GHG25 and High Oil and Gas Resource cases. Partial projection tables in Appendix D.	p. 89	p. 222

Buildings sector cases

In addition to the *AEO2013* Reference case, three technology-focused cases using the Demand Modules of NEMS were developed to examine the effects of changes in technology.

Residential sector assumptions for the technology-focused cases are as follows:

- The Integrated 2012 Demand Technology case assumes that all future residential equipment purchases are limited to the range of equipment available in 2012. Existing building shell efficiencies are assumed to be fixed at 2012 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2012.
- The Integrated High Demand Technology case assumes that residential advanced equipment is available earlier, at lower costs, and/or at higher efficiencies [*155*]. Existing building shell efficiencies exhibit 50 percent more improvement than in the Reference case after 2012. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Consumers evaluate investments in energy efficiency at a 7-percent real discount rate.
- The Integrated Best Available Demand Technology case assumes that all future residential equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each technology class, regardless of cost. Existing building shell efficiencies have twice the improvement of the Reference case after 2012. For new construction, building shell efficiencies are assumed to meet the criteria for the most efficient components after 2012. Consumers evaluate investments in energy efficiency at a 7-percent real discount rate.

Commercial sector assumptions for the technology-focused cases are as follows:

- The Integrated 2012 Demand Technology case assumes that all future commercial equipment purchases are limited to the range of equipment available in 2012. Building shell efficiencies are assumed to be fixed at 2012 levels.

- The Integrated High Demand Technology case assumes that commercial advanced equipment is available earlier, at lower costs, and/or with higher efficiencies than in the Reference case. Energy efficiency investments are evaluated at a 7-percent real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 25 percent more improvement than in the Reference case.
- The Integrated Best Available Demand Technology case assumes that all future commercial equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each technology class, regardless of cost. Energy efficiency investments are evaluated at a 7-percent real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 50 percent more improvement than in the Reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the Low Renewable Technology Cost case, which is discussed in more detail below, in the renewable fuels cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, this sensitivity case analyzes the impacts of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The Low Renewable Technology Cost case assumes greater improvements in residential and commercial PV and wind systems than in the Reference case. The assumptions for capital cost estimates are 20 percent below Reference case assumptions from 2013 through 2040.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the Residential and Commercial Demand Modules of NEMS. The Extended Policies case builds on the No Sunset case and adds multiple rounds of appliance standards and building codes as described below.

- The No Sunset case assumes that selected federal policies with sunset provisions will be extended indefinitely rather than allowed to sunset as the law currently prescribes. For the residential sector, these extensions include personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps. For the commercial sector, business ITCs for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30-percent level without reverting to 10 percent as scheduled. On January 1, 2013, the law was modified to reinstate tax credits for energy-efficient homes and selected residential appliances. The tax credits that had expired on December 31, 2011, are now extended through December 31, 2013. This change was made after the completion of *AEO2013* and is not reflected in the analysis.
- The Extended Policies case includes updates to federal appliance standards, as prescribed by the timeline in DOE's multi-year plan, and introduces new standards for products currently not covered by DOE. Efficiency levels for the updated residential appliance standards are based on current ENERGY STAR guidelines. End-use technologies eligible for No Sunset incentives are not subject to new standards. Efficiency levels for updated commercial equipment standards are based on the technology menu from the *AEO2013* Reference case and purchasing specifications for federal agencies designated by the Federal Energy Management Program. The case also adds national building codes to reach a 30-percent improvement in 2020 relative to the 2006 International Energy Conservation Code for residential households and to American Society of Heating, Refrigerating, and Air-Conditioning Engineers Standard 90.1-2004 for commercial buildings, with additional rounds of improved codes in 2023 and 2026.

Industrial sector cases

In addition to the *AEO2013* Reference case, two technology-focused cases using the IDM of NEMS were developed that examine the effects of less rapid and more rapid technology change and adoption. The energy intensity changes discussed in this section exclude the refining industry, which is modeled separately from the IDM in the LFMM. Different assumptions for the IDM were also used as part of the Integrated Low Renewable Technology Cost case, No Sunset case, and Extended Policies case, but each is structured on a set of the initial industrial assumptions used for the Integrated 2012 Demand Technology case and Integrated High Demand Technology case. The IDM assumptions for the Industrial High Resource case and the Industrial Low Resource case are based only on the Integrated High Demand Technology case. For the industrial sector, assumptions for the two technology-focused cases are as follows:

- For the Integrated 2012 Demand Technology case, the energy efficiency of new industrial plant and equipment is held constant at the 2013 level over the projection period. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing composition of output within an individual industry. Because all *AEO2013* side cases are integrated runs, potential feedback effects from energy market interactions are captured. Hence, the level and composition of overall industrial output varies from the Reference case, and any change in energy intensity in the two technology side cases is attributable to process and efficiency changes and increased use of CHP, as well as changes in the level and composition of overall industrial output.
- For the Integrated High Demand Technology case, the IDM assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*156*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes—i.e., 0.7 percent per year, as compared with 0.4 percent per year in the Reference case. The same assumption is

incorporated in the Low Renewable Technology Cost case, which focuses on electricity generation. Although the choice of the 0.7-percent annual rate of improvement in byproduct recovery is an assumption in the High Demand Technology case, it is based on the expectation of higher recovery rates and substantially increased use of CHP in that case. Due to integration with other NEMS modules, potential feedback effects from energy market interactions are captured.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the IDM of NEMS. The Extended Policies case builds on the No Sunset case and modifies selected industrial assumptions as follows:

- The No Sunset case and Extended Policies case include an assumption for CHP that extends the existing ITC for industrial CHP through the end of the projection period. Additionally, the Extended Policies case includes an increase in the capacity limitations on the ITC by increasing the cap on CHP equipment from 15 megawatts to 25 megawatts and eliminating the system-wide cap of 50 megawatts. These assumptions are based on the current proposals in H.R. 2750 and H.R. 2784 of the 112th Congress. The decline in natural gas prices related to increased domestics shale gas production is addressed in two cases, which assumer higher and lower shale gas resources than projected in the Reference case.

Transportation sector cases

In addition to the *AEO2013* Reference case, the NEMS Transportation Demand Module was used as part of four *AEO2013* side cases.

The Transportation Demand Module was used to examine the effects of advanced technology costs and efficiency improvement for technology adoption and vehicle fuel economy as part of the Integrated High Demand Technology case [*157*]. For the Integrated High Demand Technology case, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. In the freight truck sector, the Integrated High Demand Technology case assumes more rapid incremental improvement in fuel efficiency and lower costs for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

The Transportation Demand Module was used to examine the effects of an extension to the LDV GHG Emissions and CAFE Standards beyond 2025 as part of the Extended Policies case. The joint EPA and NHTSA CAFE Standards were increased after 2025, at an average annual rate of 1.4 percent through 2040, for a combined average LDV fuel economy of 57.7 miles per gallon in 2040.

Assumptions in the NEMS Transportation Demand Module were also modified for the Low/No Net Imports case. This case examines the effects of decreased VMT on the LDV transportation sector. It includes more optimistic assumptions about improvements in LDV fuel economy and reductions in LDV technology costs, lower VMT, an extension of the LDV CAFE standards beyond 2025 at an average annual rate of 1.4 percent through 2040, expanded market availability of LNG/CNG fuels for heavy-duty trucks, rail, and marine. It uses the assumptions from the optimistic battery case (*AEO2012*) for electric vehicle battery and drivetrain costs.

In the High Net Imports case, the assumptions used in the NEMS Transportation Demand Module were adjusted to incorporate a more pessimistic outlook. This case assumes lower improvement in LDV fuel economy (driven by limits on technology improvement and non-enforcement of CAFE standards), higher VMT, no change in LNG/CNG market availability, and no change in biofuel market penetration from the Reference case.

Electricity sector cases

In addition to the Reference case, several integrated cases with alternative electric power assumptions were developed to support discussions in the “Issues in focus” section of *AEO2013*. Three alternative cases were run for nuclear power plants, to address uncertainties about the operating lives of existing reactors and the potential for new nuclear capacity and capacity uprates at existing plants. These cases are discussed in the “Issues in focus” article, “Nuclear power through 2040.”

Nuclear cases

- The Low Nuclear case assumes that reactors will not receive a second license renewal, so that all existing nuclear plants are retired within 60 years of operation. The reported retirement at Oyster Creek occurs as currently planned, at the end of 2019. Also, Kewaunee is retired at the end of 2014, based on an announcement by Dominion Resources in late 2012 stating their intention to retire the unit in the next few years. Additionally, two units that are currently out of service are assumed to be permanently shut down in the Low Nuclear case. San Onofre 2 and Crystal River 3 currently are not operating, but they are assumed to be returned to service in 2015 in the Reference case. In the Low Nuclear case they are retired in 2013. In the Reference case, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal would occur for most plants that reach 60 years of operation before 2040. The Low Nuclear case was run to analyze the impact of additional nuclear retirements. In this case, no plants receive license extensions beyond 60 years, and 45 gigawatts of nuclear capacity is assumed to be retired by 2040. The Low Nuclear case assumes that no new nuclear capacity will be added throughout the projection, excluding capacity already planned or under construction. It also assumes that only those capacity uprates already reported to EIA (1.3 gigawatts) will be completed. The Reference case assumes additional uprates based on NRC surveys and industry reports.

- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding one announced retirement). In the Reference case, beyond the announced retirement of Oyster Creek, an additional 6.5 gigawatts of nuclear capacity is assumed to be retired through 2040, reflecting uncertainty about the impacts and/or costs of future aging. The High Nuclear case was run to provide a more optimistic outlook, with all licenses renewed and all plants continuing to operate economically beyond 60 years. The High Nuclear case also assumes that additional planned nuclear capacity is completed, based on combined license applications issued by the NRC and where an NRC or Atomic Safety and Licensing Board hearing has been scheduled. The Reference case assumes that 5.5 gigawatts of planned capacity are added, compared with 13.3 gigawatts of planned capacity additions in the High Nuclear case.
- The Small Modular Reactor case assumes that new advanced nuclear plants built after 2025 will be based on a smaller modular design rather than the larger AP1000 design used in the Reference case. The overnight costs are assumed to be the same as in the Reference case, but the construction lead time is reduced from 6 years to 3 years for the smaller design. The fixed operating and maintenance costs are assumed to be higher for the smaller design. To account for the time necessary for design certification, the first available online date for the small reactors is assumed to be 2025.

Renewable generation cases

In addition to the *AEO2013* Reference case, EIA developed a case with alternative assumptions about renewable generation technologies and policies to examine the effects of more aggressive improvement in the costs of renewable technologies.

- In the Low Renewable Technology Cost case, the levelized costs of new nonhydropower renewable generating technologies are assumed to be 20 percent below Reference case assumptions from 2013 through 2040. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 20 percent less expensive than in the Reference case for the same resource quantities. Assumptions for other generating technologies are unchanged from those in the Reference case. In the Low Renewable Technology Cost case, the rate of improvement in recovery of biomass byproducts from industrial processes also is increased.
- In the No Sunset case and the Extended Policies case, expiring federal tax credits targeting renewable electricity are assumed to be permanently extended. This applies to the PTC, which is a tax credit of 2.2 cents per kilowatthour available for the first 10 years of production by new generators using wind, geothermal, and certain biomass fuels, or a tax credit of 1.1 cents per kilowatthour available for the first 10 years of production by new generators using geothermal energy, certain hydroelectric technologies, and biomass fuels not eligible for the full credit of 2.2 cents per kilowatthour. This tax credit had been scheduled to expire on December 31, 2012 for wind and 1 year later for other eligible technologies. The same schedule applies to the 30-percent ITC, which is available to new solar installations through December 31, 2016, and may also be claimed in lieu of the PTC for eligible technologies, expiring concurrently with the PTC (described above). On January 1, 2013, the law was modified to extend the expiration date for wind by one full year and to allow new plants using any eligible technology to qualify if they were under construction by the deadline—not actually in commercial service by the deadline, as was previously required. However, this change occurred too late to allow for inclusion in this report.

Oil and gas supply cases

The sensitivity of the *AEO2013* projections to changes in assumptions regarding technically recoverable domestic crude oil and natural gas resources is examined in two cases. These cases do not represent a confidence interval for future domestic oil and natural gas supply but rather provide a framework to examine the impact of higher and lower domestic supply on energy demand, imports, and prices. Assumptions associated with these cases are described below.

- In the Low Oil and Gas Resource case, the EUR per tight oil, tight gas, and shale gas well is assumed to be 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved technically recoverable resource (TRR) of crude oil is decreased to 168 billion barrels, and the natural gas resource is decreased to 1,500 trillion cubic feet, as compared with unproved resource estimates of 197 billion barrels of crude oil and 2,022 trillion cubic feet of natural gas in the Reference case as of January 1, 2011.
- In the High Oil and Gas Resource case, the resource assumptions are adjusted to give continued increase in domestic crude oil production after 2020, reaching over 10 million barrels per day. This case includes: (1) 100 percent higher EUR per tight oil, tight gas, and shale gas well than in the Reference case and a maximum well spacing of 40 acres, to reflect the possibility that additional layers of low-permeability zones are identified and developed, compared with well spacing that ranges from 20 to 406 acres with an average of 100 acres in the Reference case; (2) kerogen development reaching 135,000 barrels per day in 2025; (3) tight oil development in Alaska increasing the total Alaska TRR by 1.9 billion barrels; and (4) 50 percent higher technically recoverable undiscovered resources in Alaska and the offshore lower 48 states than in the Reference case. Additionally, a few offshore Alaska fields are assumed to be discovered and thus developed earlier than in the Reference case. Given the higher natural gas resource in this case, the maximum penetration rate for GTL was increased to 10 percent per year, compared to a rate of 5 percent per year in the Reference case.

Liquids market cases

Two sensitivity cases have been designed to analyze petroleum imports in the United States. Assumptions associated with these cases are described below.

- In the Low/No Net Imports case, changes were made to various NEMS modeling assumptions that, in comparison with the *AEO2013* reference case, resulted in higher domestic production of crude oil and natural gas, lower domestic liquid fuels demand, and higher domestic production of nonpetroleum liquids. The methodology used to achieve higher domestic crude production is the same as that used in the High Oil and Gas Resource case (described in the "Oil and gas supply cases" section above). Domestic liquid fuels demand was reduced by changes made in the Transportation Demand Module. As described in the "Transportation sector cases" section, this included the use of more optimistic assumptions about improvements in LDV fuel economy and reductions in LDV technology costs; lower VMT due to changes in consumer behavior; an extension of the LDV CAFE standards beyond 2025 at an average annual rate of 1.4 percent through 2040; expanded market availability of LNG/CNG fuels for heavy-duty trucks, rail, and marine; and use of assumptions from the optimistic battery case (*AEO2012*) for electric vehicle battery and drivetrain costs. Within the LFMM, the assumption for market penetration of biomass pyrolysis oils, CTL, and BTL production was more optimistic. Also, initial assumptions associated with E85 availability and maximum penetration of E15 were set to be more optimistic, such that E85 availability was nearly three times the Reference case level in 2040, and E15 penetration was about 15 percent higher by 2040.
- In the High Net Imports case, changes were made in two NEMS modules to reduce domestic crude oil production and increase domestic demand for liquid fuels, as compared with the Reference case. The methodology used to achieve lower domestic crude production is the same as that used in the Low Oil and Gas Resource case described above. An increase in domestic liquids fuels demand was achieved by assuming lower improvement in vehicle efficiency (driven by limits on technology improvement and non-enforcement of CAFE standards and resulting in a lower number of alternatively fueled vehicles, including hybrid, plug-in hybrid, and battery electric vehicles); higher VMT; no change in LNG/CNG market availability; no change in GTL penetration; and no change in biofuel market penetration compared with the Reference case.

Coal market cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates. The alternative productivity and cost assumptions are applied in every year from 2013 through 2040. For the coal cost cases, adjustments to the Reference case assumptions for coal mining productivity are based on variation in the average annual productivity growth of 2.5 percent observed since 2000 for mines in Wyoming's Powder River Basin and 2.4 percent for other coal-producing regions. Transportation rates are lowered (in the Low Coal Cost case) or raised (in the High Coal Cost case) from Reference case levels to achieve a 25-percent change in rates relative to the Reference case in 2040. The Low and High Coal Cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the Low Coal Cost case, the average annual growth rates for coal mining productivity are higher than those in the Reference case and are applied at the supply curve level. As an example, the average annual productivity growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -1.6 percent in the Reference case for the years 2013 through 2040 to 0.9 percent in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs all are assumed to be about 25 percent lower in 2040 in real terms in the Low Coal Cost case than in the Reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower in 2040.
- In the High Coal Cost case, the average annual productivity growth rates for coal mining are lower than those in the Reference case and are applied as described in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs in 2040 are assumed to be about 32 percent higher than in the Reference case, and coal transportation rates in 2040 are assumed to be 25 percent higher.

Additional data on productivity, wage, mine equipment cost, and coal transportation rate assumptions for the Reference and alternative coal cost cases are shown in Appendix D.

Cross-cutting integrated cases

A series of cross-cutting integrated cases are used in *AEO2013* to analyze specific cases with broader sectoral impacts. For example, three integrated technology progress cases analyze the impacts of faster and slower technology improvement in the demand sector (partially described in the sector-specific sections above). In addition, seven cases were run with alternative assumptions about expectations of future regulation of GHG emissions.

Integrated technology cases

In the demand sectors (residential, commercial, industrial, and transportation), technology improvement typically means greater efficiency and/or reduced technology cost. Three alternative demand technology cases—Integrated 2012 Demand Technology, Integrated Best Available Demand Technology, and Integrated High Demand Technology cases—are used in *AEO2013* to examine the potential impacts of variation in the rate of technology improvement in the end-use demand sectors, independent of any offsetting impacts of variations in technology improvement in the supply/conversion sectors. Assumptions for each end-use sector are described in the sector-specific sections above.

No Sunset case

In addition to the *AEO2013* Reference case a No Sunset case was run, assuming that selected federal policies with sunset provisions—such as the PTC, ITC, and tax credits for renewable and CHP equipment in the buildings and industrial sectors—will be extended indefinitely rather than allowed to sunset as the law currently prescribes. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

Extended Policies case

In the Extended Policies case, assumptions for tax credit extensions are the same as in the No Sunset case described above. Further, updates to federal appliance efficiency standards are assumed to occur at regular intervals, and new standards for products not currently covered by DOE are assumed to be introduced. Finally, fuel economy standards for LDVs, including both passenger cars and light-duty trucks, are assumed to continue increasing after 2025. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

Greenhouse gas cases

Given concerns about climate change and possible future policy actions to limit GHG emissions, regulators and the investment community are beginning to push energy companies to invest in technologies that are less GHG-intensive. To reflect the market's current reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital is assumed for investments in new coal-fired power plants without CCS and for all capital investment projects at existing coal-fired power plants in the Reference case and all other *AEO2013* cases except the No GHG Concern case, GHG10 case, GHG15 case, GHG25 case, GHG10 and Low Gas Prices case, GHG15 and Low Gas Prices case, and GHG25 and Low Gas Prices case. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation.

The seven alternative GHG cases are used to provide a range of potential outcomes, from no concern about future GHG legislation to the imposition of a specific economywide carbon emissions price, as well as an examination of the impact of a combination of specific economywide carbon emissions prices and low natural gas prices. *AEO2013* includes six economywide CO_2 price cases, combining three levels of carbon prices with two alternative gas price projections. In the GHG10 case and GHG10 and Low Gas Prices case, the carbon emissions price is set at $10 per metric ton CO_2 in 2014. In the GHG15 case and GHG15 and Low Gas Prices case, the carbon emissions price is set at $15 per metric ton CO_2 in 2014. In the GHG25 case and GHG25 and Low Gas Prices case, the price is set at $25 per metric ton CO_2 in 2014. In all cases the price begins to rise in 2014 at 5 percent per year. The GHG10, GHG15, and GHG25 cases use the Reference case assumptions regarding oil and gas resource availability. The GHG10 and Low Gas Prices case, GHG15 and Low Gas Prices case, and GHG25 and Low Gas Prices case use the assumptions from the High Oil and Gas Resource case, as described above in the "Oil and gas supply" section. The GHG cases are intended to measure the sensitivity of the *AEO2013* projections to a range of implicit or explicit valuations of CO_2. At the time *AEO2013* was completed, no legislation including a GHG price was pending; however, the EPA is developing technology-based CO_2 standards for new coal-fired power plants. In the GHG cases for *AEO2013*, no assumptions are made with regard to offsets, policies to promote CCS, or specific policies to mitigate impacts in selected sectors.

The No GHG Concern case was run without any adjustment for concern about potential GHG regulations (without the 3-percentage-point increase in the cost of capital). In the No GHG Concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type.

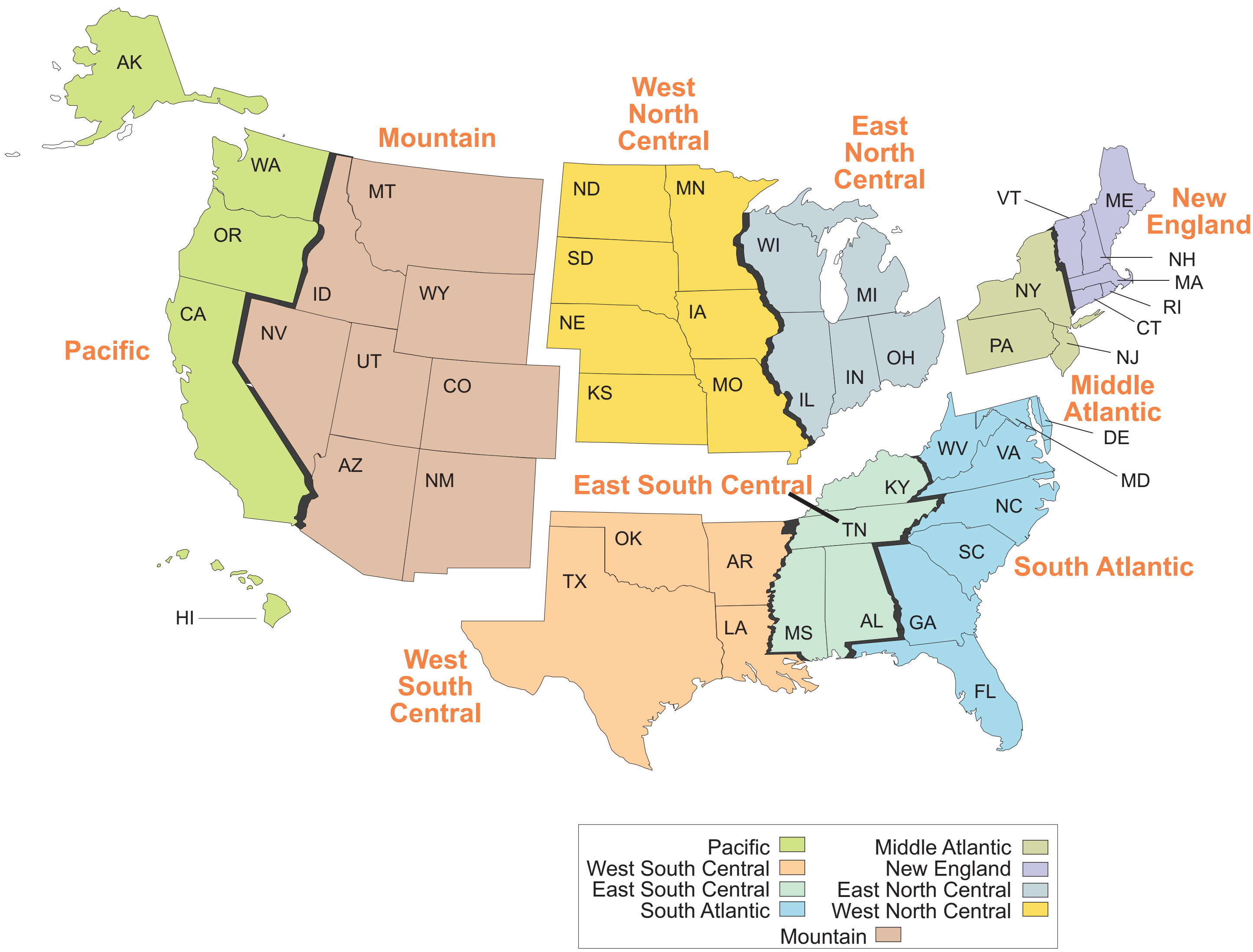
Endnotes for Appendix E

Links current as of March 2013

148. U.S. Energy Information Administration, *The National Energy Modeling System: An Overview 2009*, DOE/EIA-0581(2009) (Washington, DC: October 2009), website www.eia.gov/oiaf/aeo/overview.
149. U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC: September 2012), website www.eia.gov/aer.
150. U.S. Energy Information Administration, *Short-Term Energy Outlook September 2012* (Washington, DC: September 2012), website www.eia.gov/forecasts/steo/archives/Sep12.pdf. Portions of the preliminary information were also used to initialize the NEMS Liquids Fuels Market Module projection.
151. U.S. Energy Information Administration, "Short-Term Energy Outlook" (Washington, DC: January 2013), website www.eia.gov/forecasts/steo/outlook.cfm.
152. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013*, DOE/EIA-0554(2013) (Washington, DC: April 2013), website www.eia.gov/forecasts/aeo/assumptions.
153. Alternative other liquids technologies include all biofuels technologies plus CTL and GTL.
154. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013*, DOE/EIA-0554(2013) (Washington, DC: April 2013), website www.eia.gov/forecasts/aeo/assumptions.
155. High technology assumptions for the buildings sector are based on U.S. Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, September 2011), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, November 2012).
156. These assumptions are based in part on U.S. Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
157. U.S. Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).

Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F1. United States Census Divisions (continued)

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

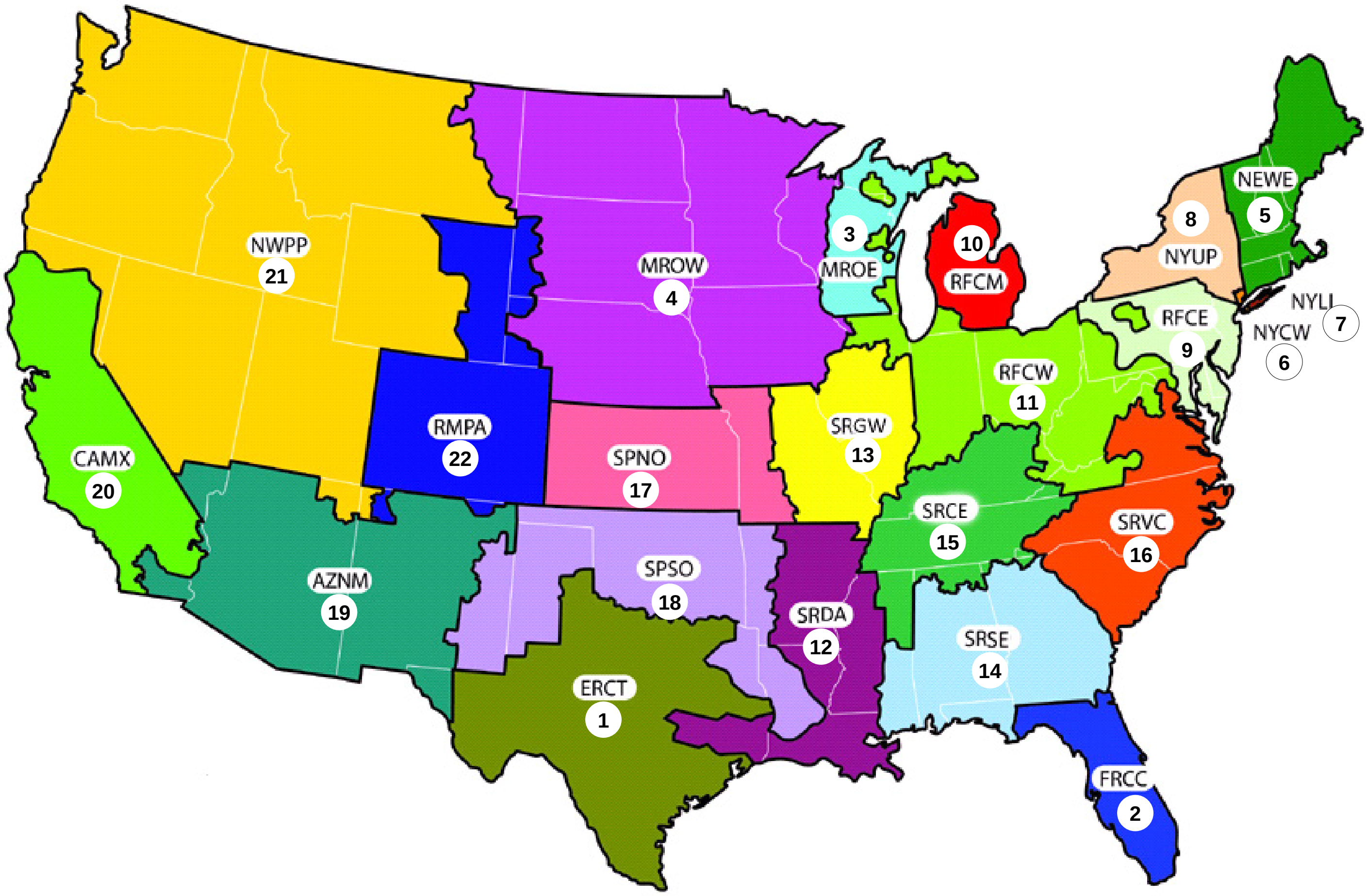
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

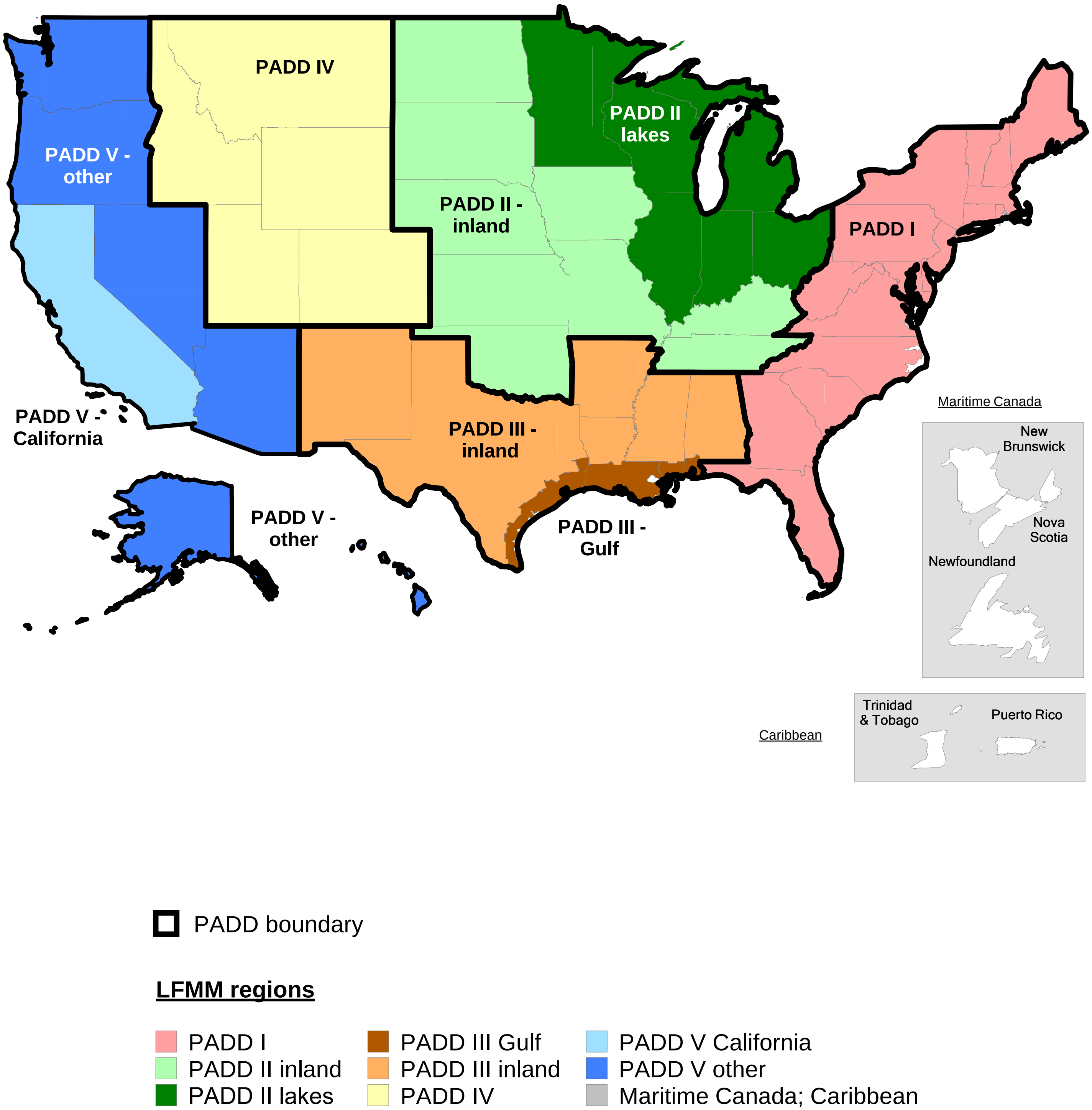
Figure F2. Electricity market module regions



1.	ERCT	TRE All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Source: U.S. Energy Information Administration, Office of Energy Analysis.

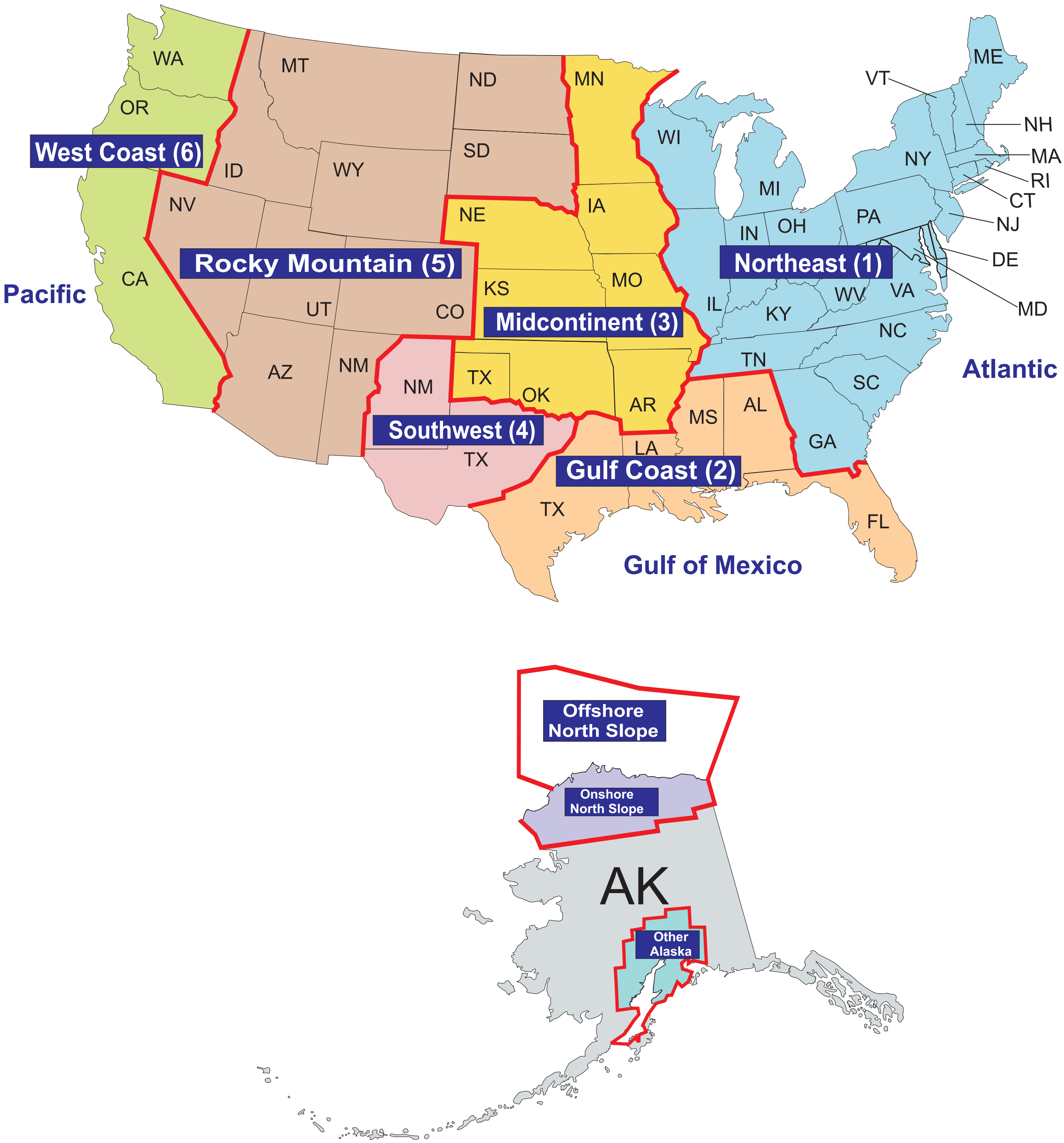
Figure F3. Liquid fuels market module regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

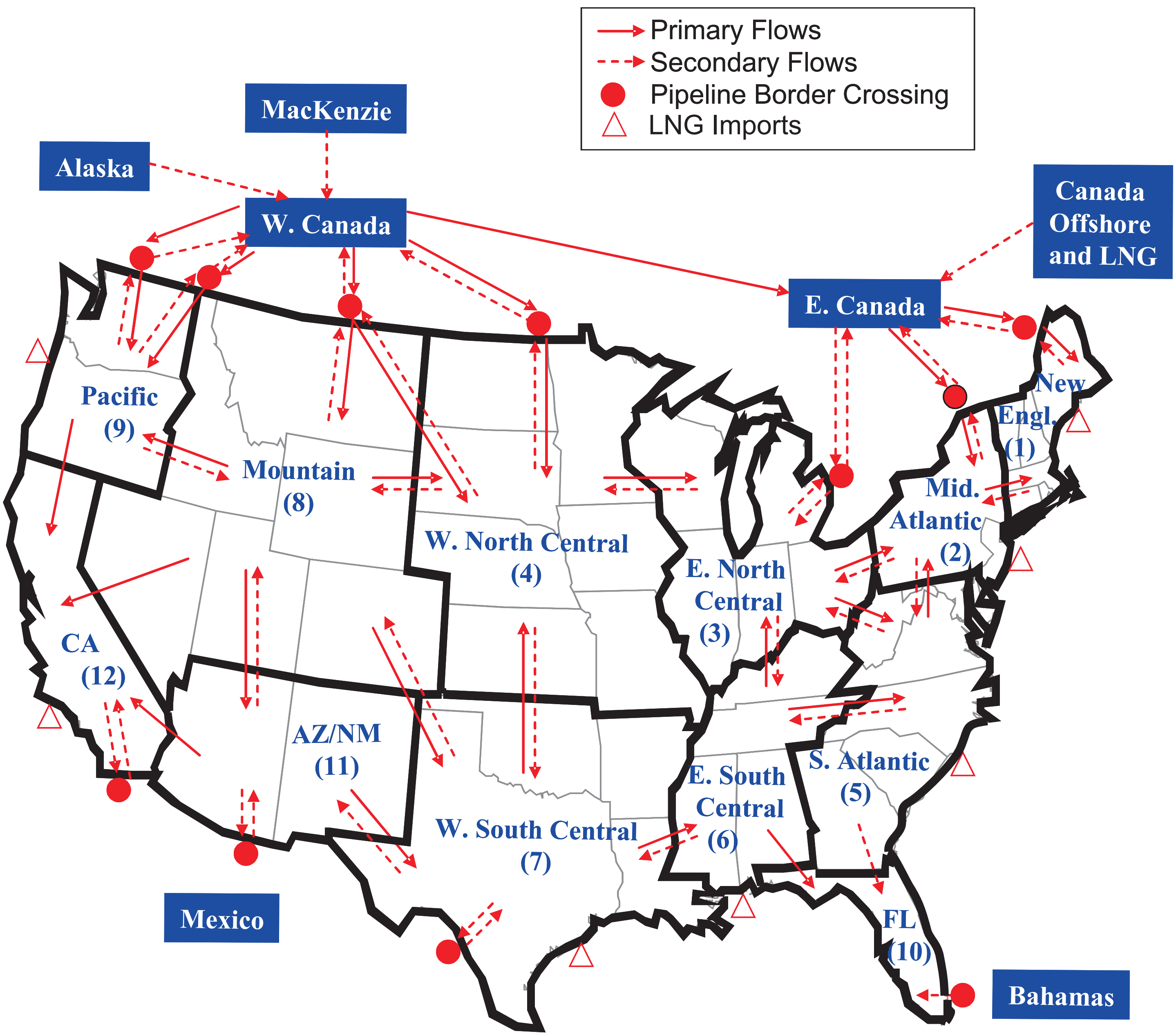
Source

Figure F4. Oil and gas supply model regions



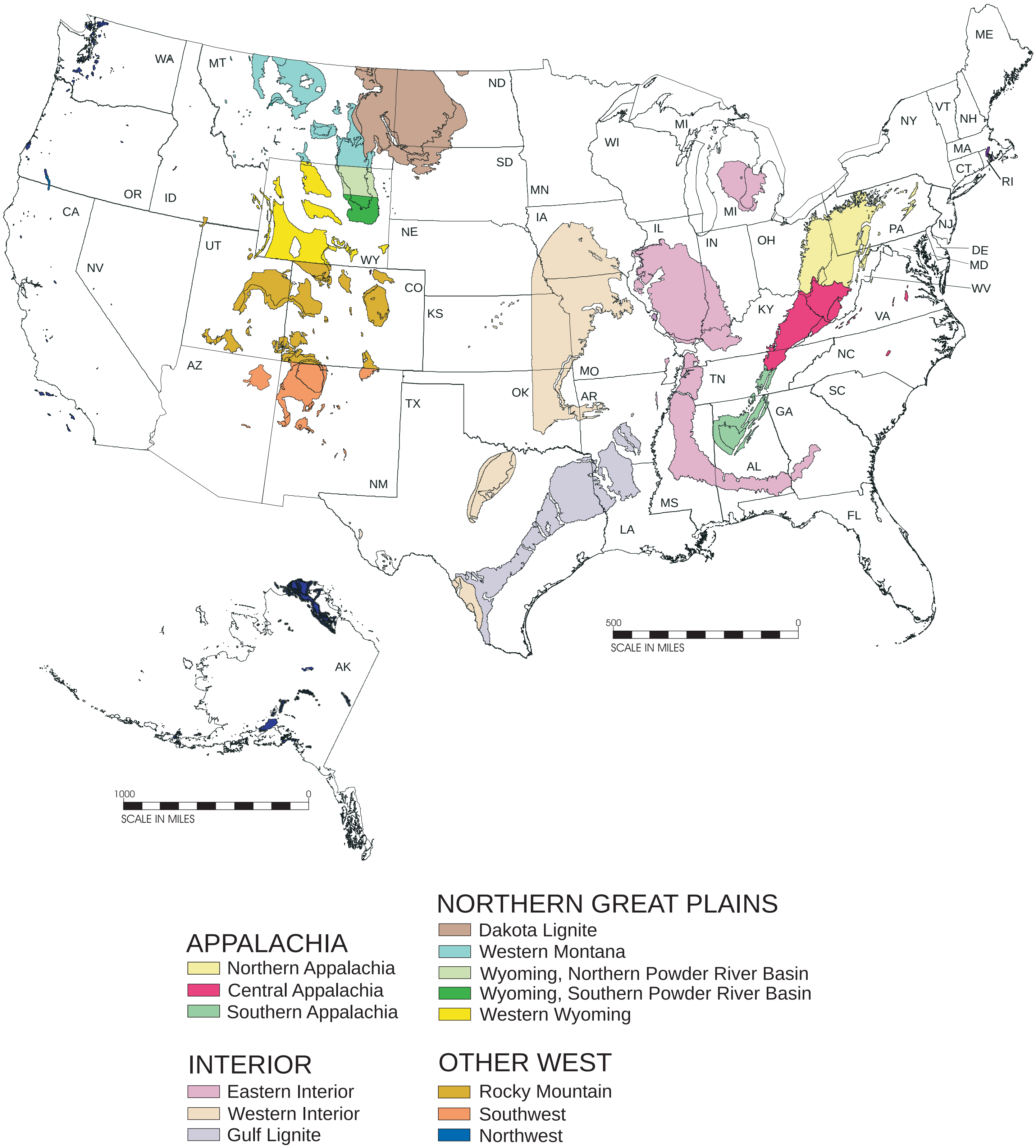
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



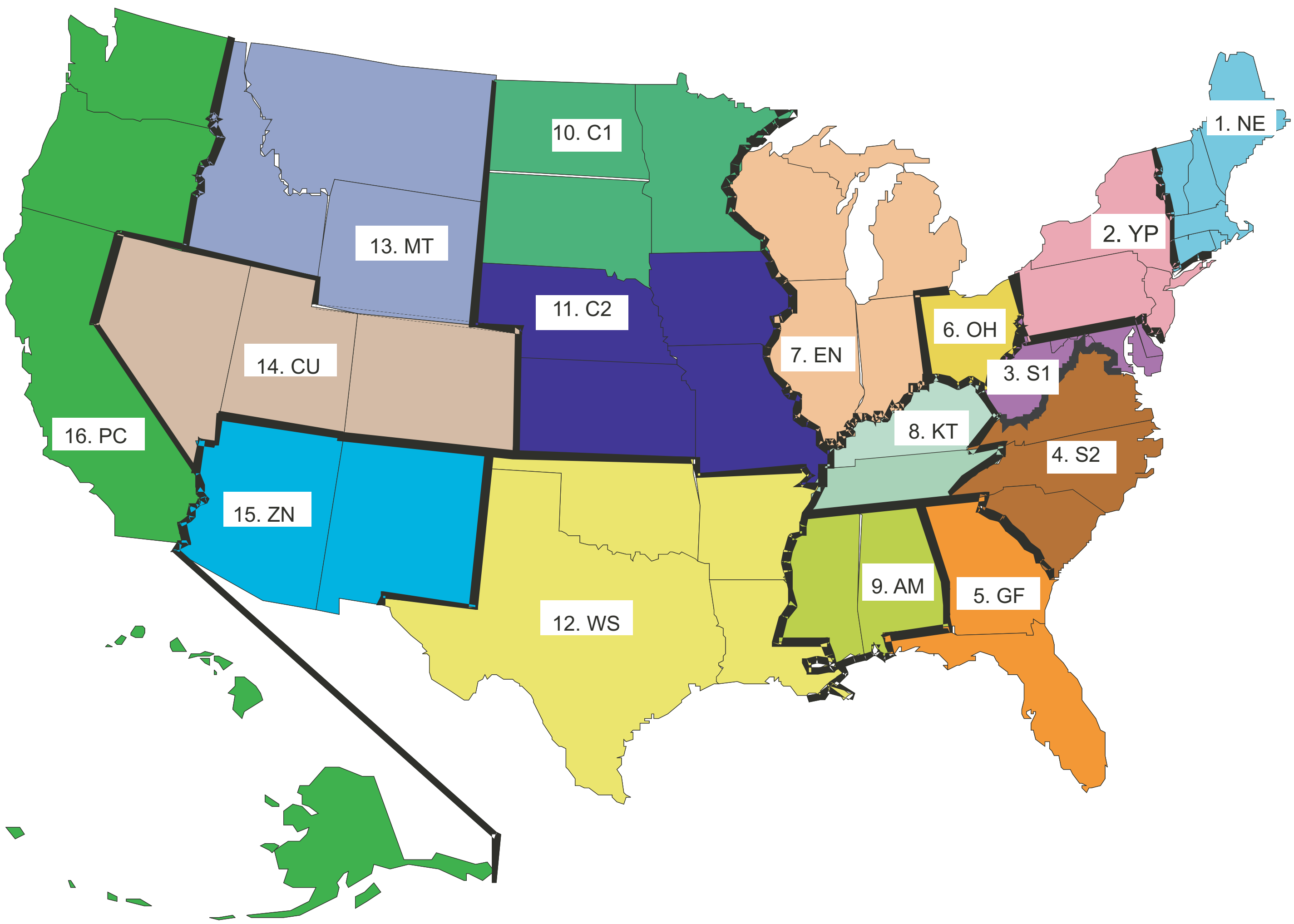
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Coal supply regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F7. Coal demand regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Conversion factors

Table G1. Heat contents

Fuel	Units	Approximate heat content
Coal[1]		
Production	million Btu per short ton	20.136
Consumption	million Btu per short ton	19.810
Coke plants	million Btu per short ton	26.304
Industrial	million Btu per short ton	23.651
Residential and commercial	million Btu per short ton	20.698
Electric power sector	million Btu per short ton	19.370
Imports	million Btu per short ton	25.394
Exports	million Btu per short ton	25.639
Coal coke	million Btu per short ton	24.800
Crude oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.967
Petroleum products and other liquids		
Consumption[1]	million Btu per barrel	5.353
Motor gasoline[1]	million Btu per barrel	5.048
Jet fuel	million Btu per barrel	5.670
Distillate fuel oil[1]	million Btu per barrel	5.762
Diesel fuel[1]	million Btu per barrel	5.759
Residual fuel oil	million Btu per barrel	6.287
Liquefied petroleum gases[1]	million Btu per barrel	3.577
Kerosene	million Btu per barrel	5.670
Petrochemical feedstocks[1]	million Btu per barrel	5.114
Unfinished oils	million Btu per barrel	6.039
Imports[1]	million Btu per barrel	5.580
Exports[1]	million Btu per barrel	5.619
Ethanol	million Btu per barrel	3.560
Biodiesel	million Btu per barrel	5.359
Natural gas plant liquids		
Production[1]	million Btu per barrel	3.566
Natural gas[1]		
Production, dry	Btu per cubic foot	1,022
Consumption	Btu per cubic foot	1,022
End-use sectors	Btu per cubic foot	1,023
Electric power sector	Btu per cubic foot	1,021
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2011.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

Large scale export of East Coast Australia natural gas: Unintended consequences

A study of the national interest effects of the structure of the Australian gas industry.

A report to
The Australian Industry Group and the Plastics and Chemicals Industries Association

Prepared by the
National Institute of Economic and Industry Research
ABN: 72 006 234 626
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October 2012

While the National Institute endeavours to provide reliable forecasts and believes the material is accurate it will not be liable for any claim by any party acting on such information.

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Executive summary

***"**One molecule of natural gas is chemically the same as another, but where it is found has enormous implications for global politics.*

The price of gas in the US following the shale drilling boom is now a third of that in western Europe and a fifth of that in Asia."

Financial Times, 17 July 2012

"Gas prices on the eastern seaboard will follow the big rises already hitting downstream industrial users in Western Australia, says Santos chief executive David Knox.

At a Sydney forum on the future of gas, Mr Knox stated that prices in the east of between $3 and $4 a gigajoule would rise to between $6 and $9 for new domestic customers as increasing volumes were exported.

That is the range we are talking about for anyone coming to us now," he said. "We are actively negotiating with a number of buyers … and you are going to see an increase in prices."

Australian Financial Review, 23 August 2012

Natural gas is a fundamental source of energy for power generation, industry, consumers, hospitals and institutions generally. In today's world of transition to greater use of renewable energy it plays an important role in facilitating cost effective peaking power to fill the gaps when renewable supply is not available. It is both an efficient relatively clean fuel source and a critical feedstock for conversion by industry into value-added consumer products. Its value to the domestic economy is very significant as the alternatives are less efficient and, in the case of coal and oil, have significantly higher greenhouse gas emissions.

Many major projects to export Liquefied Natural Gas from Eastern Australia have been approved and will start to operate over the next several years. This will significantly impact the domestic supply of natural gas. In this report we do not argue against the export of LNG but emphasise that the benefits from exporting LNG should be weighed against the benefits of ensuring competitive supply to the domestic gas-dependent manufacturing sector. In a market where there are sufficient reserves of the resource, as appears to be the case in Australia, the typical response would be for additional supply to be made available to meet domestic demand. However, due to the nature of the gas resources, their location, limitations in infrastructure and the way in which we manage these resources, there is a serious risk that this will not be the case. Even a temporary period without secure access to domestic gas would have significant unintended consequences, as would a shift to LNG-linked gas pricing. As such, it is prudent to look at the implications of these developments for consumers and industry.

The National Institute of Economic and Industry Research (NIEIR) has made such an assessment, reviewing the literature and conducting its own assessment of the sectoral and macroeconomic implications of these developments. The findings are concerning.

NIEIR has found that:

- if existing plans proceed, gas exports from eastern Australia will rise from 2 million tonnes in 2015 to 20 million tonnes in 2018, and possibly 24 million tonnes in 2023;

- the current policy framework and market settings for the Australian gas industry favour export of LNG without a subsequent assurance of reliable, competitively priced supplies of gas for domestic industry. Such supplies have historically been a competitive advantage for Australian industry, and gas export revenue is insufficient to compensate Australia for the loss of this advantage;

- natural gas is essential to a range of industries, particularly non-ferrous metals and basic chemicals, but also plastics, pharmaceuticals, paints and cosmetics. Secure local supply at competitive prices is a fundamental requirement for the continuation of a significant part of production and the development of new investment in these industries;

- contracts for the long term supply of gas to domestic industry have 'evaporated' as a consequence of export commitments;

- Australia has only a few years before significant economic loss is likely to be felt from the failure to secure an affordable supply of natural gas to domestic users;

- domestic gas users are increasingly being offered "surplus" gas volumes and prices that do not reflect domestic supply, demand or extraction costs, but are instead linked to East Asia's LNG market – the highest-priced gas in the world. This is a radical reshaping of the domestic gas market, constraining supply (in the near term at least) and driving prices to high (and for many industries uneconomic) levels;

- current gas production and proven reserves will need to expand dramatically in order to support the LNG expansion without significant large scale suppression of gas use on the domestic economy. While the total gas resource is thought to be very large, proving up additional resources and developing them will take time and faces community opposition and other barriers. To ensure gas availability for domestic users, the management of reserves and their supply to market needs attention if domestic needs are not to be overlooked in the rush to export this valuable resource;

- there are important opportunities to expand use of gas in industrial production and electricity generation, but even so domestic consumers cannot make use of the whole gas resource. There are worthwhile benefits to pursue from exporting gas production beyond these needs. But each petajoule of natural gas that is shifted **away** from industrial use **towards** export, whether because of tight supply or uneconomic pricing, means giving up $255 million in lost industrial output for a $12 million gain in export output. That is, for every dollar gained $21 is lost. This increases to $24 when economy-wide impacts are taken into account;

- the dramatic shift in the domestic gas market will have wider impacts well beyond the gas intensive industries:

    - increased operating costs for gas-fired electricity generators due to high gas prices. Such generators would see cost increases three times greater than those currently resulting from the carbon tax. Wholesale electricity prices would thus rise, and the viability of new gas-fired generation would suffer. These plants already play an important role in the electricity market for both peak power and base load. That role is expected to grow to meet emissions reduction targets and provide backup for expanding renewable generation;

- some substitution away from gas towards electricity by business and households, to reduce their exposure to rising gas prices. This would still leave their costs higher than at present, and would raise greenhouse emissions;

- a slow-down of general economic activity resulting from impacts of the tighter gas supply and higher costs for gas and electricity;

- the expected economic response to the East Coast LNG expansion will involve a combination of the adjustments above. As a result, modelling indicates that, by 2040 the gross production benefit for East Coast LNG expansion will be $15 billion annually, in 2009 prices. However, taking into account the negative effects of adjustment on other sectors, annual GDP will be $22 billion lower than it would be with secure and affordable gas. An alternative ‘benefit indicator’ used for this study, which combines private consumption, tax receipts and net national product, will be reduced by $46 billion;

- under current policy settings and market structures, the unwanted consequences of the significant boom in LNG exports will persist even if, as is likely, adequate natural gas reserves exist and are brought to market; and

- there are substantial further risks that would lead to even greater costs if realised. These risks include:

  (i) LNG prices may be lower than currently expected. While this would reduce the extent of domestic price rises, it would also reduce gross export benefits while leaving domestic supply constrained in the short-to-medium term by contracted export commitments; and

  (ii) industry will likely be unable to grow without secure affordable gas supplies, leading to additional damage.

The rules of thumb developed in this study for these additional effects are:

- for every 1 per cent reduction in the LNG price the economy-wide benefits from LNG exports will be reduced by approximately 2 percentage points. This stems mainly from the fact that tax receipts and domestic profits will be disproportionately impacted. Foreign interest payments and repayment of debt will still have to be paid; and

- for every $1m of existing chemical industry output that is saved by increased natural gas supply there is another $1m of output that can be obtained by using the competitive advantages for domestic natural gas availability in general, and natural gas liquids in particular.

The likely consequences of the current policy and industry settings on natural gas export are serious for both industry and households. There is an urgent need for more recognition of these impacts, and for a debate on how they can be prevented, alleviated or adapted to. LNG export is a positive for Australia as long as it proceeds without significant harm to the domestic sector and with confident assurance of domestic supply.

1. Background and study objective

1.1 Background

Natural gas is an essential input to value creation and productivity in many of Australia's key industries. If the supply of natural gas is threatened or, short of this, confidence in its ready availability at competitive prices is weakened, so too are the industries that use the gas as a raw material or fuel. Current developments in Queensland, focusing on LNG exports, are threatening Eastern Australia's gas-dependent industries by weakening confidence that gas will be available at competitive cost.

In this report we do not argue against the export of LNG but emphasise that the benefits from exporting LNG should be weighed against the benefits of ensuring competitive supply to the domestic gas-dependent manufacturing sector. Our work indicates that the national benefit from the supply of gas to the many industries that are involved is many times the gain due to export of the same quantity of gas.

Taking these benefits into account, from the beginning the Western Australian Government was active in ensuring that domestic use of the offshore North West Shelf gas resource was to be protected. The Government explicitly committed to actively ensuring that this would be the case. The provisions of the original LNG Act drafted in the 1970s to pave the way for Australia's first LNG export project are specific in the way the reserves are to be used for both export and domestic users. Two sections of the Act indicate this.

"***Notification of additional reserves of natural gas***

20. If the Joint Venturers discover reserves of natural gas additional to those required for their commitments contemplated in recitals (c) and (d) of this Agreement during their exploration programme in the offshore Dampier region (carried out under the provision of the Petroleum (Submerged Lands) Acts), which in the opinion of the Joint Venturers are capable of commercial development the Joint Venturers shall –

(a) notify the Minister of the extent and nature of such additional reserves;

(b) having regard to the State's desire for the petrochemical industry to be established in Western Australia, investigate the processing of all or part of such natural gas for use as petrochemical feedstock; and

(c) enter into discussions with the Minister concerning the utilisation of such natural gas."

"Marketing authorisation

42. The State authorises the Joint Venturers and each of them subject to the provisions of this Agreement and pursuant to recital (c) hereof to sell gas to the State Energy Commission and pursuant to such gas agreements with the State Energy Commission –

(a) to market gas in the Pilbara to each of their affiliated companies and to major industrial customers who use more than 28 000 cubic metres of gas per day;

> (b) *to sell or supply gas to each of their affiliated companies anywhere in Western Australia;*
>
> (c) *to construct, finance and operate gas transmission pipelines to each of their customers in the Pilbara."*

The benchmark price for domestic sales from the Joint Venture was set with a high weight given to domestic cost levels and competitiveness.

In terms of new fields in this century, the Western Australian Government has imposed a reservation policy where 15 per cent of the natural gas reserves are required to be used for domestic purposes.

The case is very different for Queensland. As of 2012 three major LNG plants are under construction in Gladstone on the Queensland central coast. These projects have been approved to proceed without any conditions or arrangements being put in place to generate supply at competitive prices to domestic gas users, whether they are heavy industrial users, commercial business, electricity generators or households.

With the advent of LNG projects the situation changed quickly for Queensland domestic gas customers and increasingly for large users across the east coast. Previously users were offered long-term contracts with predictable price settings. They could undertake long-term investments underpinned by a secure and cost-stable energy supply.

Currently, long-term contracts have "evaporated" as the first priority of gas producers is to secure supply for their LNG plants. Domestic customers feel the domestic market is now the residual sector, allocated what is surplus to requirements for the LNG plants, a reality which will become obvious once existing gas contracts end. Medium-term, let alone long-term, security of supply is no longer guaranteed. Domestic customers are now faced with the expectation having to pay the "net back" LNG price for natural gas, involving most probably a significant increase in price and, more importantly, the introduction of considerable price uncertainty derived from the unpredictability of the world gas market.

Admittedly, it is difficult to be precise about the calculation of 'net back' prices. Because of the variation in contract arrangements between LNG projects, the concept of a world LNG price is difficult to apply and actual prices will be determined by specific contract provisions. The provisions may or may not relate to LNG prices from other sources, either in Australia or overseas.

However, the concept of a domestic gas price based on a 'net back' price for LNG may not be the only factor leading to increased and more variable prices. Domestic consumers expect that the large impact of LNG demand on reserves will force domestic supply to be sourced from fields with higher extraction costs and, therefore, higher domestic cost. Since the majority of gas reserves are leased by interested parties focussed on LNG, it now appears likely that the domestic customers will be matched to the marginal increment in gross supply costs.

This is an extraordinary state of affairs given the scale of the projects and scale of the impact on the existing Australian identified reserves of natural gas. In the application of the national interest test to the projects which governments are obliged to do as manager of the resource on behalf of the community, it appears unlikely that the impacts of the LNG projects on domestic gas using industries have been considered to any great extent. This has been done in private sector reports, such as "*Carbon Market Economics – The Impact of Liquefied Natural Gas on Queensland Gas markets and Gas Users*", March 2010, with to date little impact in changing arrangements.

Australian natural gas (identified and potential) reserves are owned by the Crown which obliges the government of the day to determine when and how the resources are to be used. In exercising this duty, the government has a responsibility to optimise the benefit which current and future generators obtain from the extraction of the resources. Under the Australian constitution there are Federal/State Government jurisdiction issues as to who is responsible, but the reality is that all areas of Government need to cooperate to solve the problem.

1.2 Study objective

Accordingly, the study objective is to:

(i) outline a framework for testing the national interest benefit of Eastern Australian LNG projects that should be applied by the responsible Governments;

(ii) apply the framework to assess the net benefits that are likely to be obtained from the current projects under the current terms and conditions of their approval; and

(iii) evaluate the impact of alternative terms and conditions, in terms of assessing whether or not the net benefits assessed in (ii) can be significantly increased.

In short, this report complements the *Carbon Market Economics* (CME) report by quantifying the macroeconomic costs of a less than satisfactory (that is deficient) national interest evaluation and appropriate complementary policy design.

1.3 The LNG industry evaluated by this study

The LNG industry evaluated by this national interest evaluation is LNG exports from Queensland. The question at issue is whether Australia will obtain a net benefit from expected exports of LNG from Queensland. The expansion profile assumed in the quantitative analysis of the issue is:

**Exports of LNG from Queensland
(million tonnes)**

2015	2
2016	15
2017	18
2018	20
2019	20
2020	20
2021	20
2022	20
2023	24

In simple terms, therefore, the study will attempt to answer the question of whether or not Australia will obtain a net benefit from 24 million tonnes per annum of natural gas export from Queensland.

1.4 Why the focus on East Coast LNG?

The focus on East Coast LNG is because:

(i) the Western Australian market is not connected to the integrated gas market of the Eastern Australian states (which for this purpose include South Australia but not the Northern Territory) and

(ii) Western Australia has a domestic reservation policy for natural gas and the eastern states do not.

Because of the inter-connection between the eastern states' markets, the East Coast LNG plants will affect the majority of the Australian economy.

In short, given the conditions under which the Queensland projects were allowed to proceed, it is these projects that are most likely to fail a comprehensive national interest test.

1.5 Construction impacts

This study focuses on the production impacts on the economy. The construction impacts of new capacity required to support the changes is ignored as there is no suggestion that the LNG projects should not proceed but the focus should be on ensuring there is ample gas for the domestic sector.

2. The national interest evaluation framework, indicators and methodology

Under Australian law, Australia's petroleum (including natural gas) resources (and mineral resources) are owned by the Crown, in some cases in the right of the states and territories and in some cases in the right of the Commonwealth. In the words of the Productivity Commission, governments should exercise stewardship over Crown resources, managing them to achieve maximum overall benefits for the community. As the Productivity Commission notes, management should not simply be focussed on economic benefits but should also take into account objectives such as the protection of health, the environment and heritage. In general terms, the governance requirement is expressed as the Government's responsibility to make decisions on:

- how;
- when; and
- on what terms,

the petroleum resources are extracted, in terms of maximising the national interest.

Although the national interest test is required in legislation, for example, for assessing foreign investment proposals, Australian Governments have not explicitly stated what guidelines should be applied in balancing the economic, environment, strategic or social interests that constitute the national interest. While this allows regulatory bodies to operate with maximum flexibility, it also shields their decisions from evaluation in terms of explicit criteria.

2.1 The national interest test

The latest statement on the national interest test was made on behalf of the Australian Government by the Treasurer.[1] The statement applies to foreign investment but would be equally relevant to resource management decisions, and not only for the reason that most resource management decisions have a foreign investment component. The statement runs as follows.

2.1.1 What are the characteristics of investment proposals that are likely to be approved

The Government is making sure investments are not contrary to the national interest. If an investment is contrary to the national interest, the Government will intervene. This occurs infrequently.

What is contrary to the national interest cannot be answered with hard and fast rules. Attempting to do so can prohibit beneficial investments and that is not the intention of our regime. Australia's case-by-case approach maximises investment flows while protecting Australia's national interest.

---

1 The Treasurer of Australia, "*Australian Foreign Investment Policy*", January 2012.

2.1.2 What are the national interest considerations

Assessing the national interest allows the Government to balance potential sensitivities against the benefits of foreign investment.

The Government determines national interest concerns case-by-case. We look at a range of factors and the relative importance of these can vary depending upon the nature of the target enterprise. Investments in enterprises that are large employers or that have significant market share may raise more sensitivities than investments in smaller enterprises. However, investments in small enterprises with unique assets or in sensitive industries may also raise concerns.

The impact of the investment is also a consideration. An investment that enhances economic activity – such as by developing additional productive capacity or new technology – is less likely to be contrary to the national interest.

The Government typically considers the following factors when assessing foreign investment proposals.

National Security

The Government considers the extent to which investments affect Australia's ability to protect its strategic and security interests. The Government relies on advice from the relevant national security agencies for assessments as to whether an investment raises national security issues.

Competition

The Government favours diversity of ownership within Australian industries and sectors to promote healthy competition. The Government considers whether a proposed investment may result in an investor gaining control over market pricing and production of a good or service in Australia. For example, the Government will carefully consider a proposal that involves a customer of a product gaining control over an existing Australian producer of the product, particularly if it involves a significant producer.

The Government may also consider the impact that a proposed investment has on the make-up of the relevant global industry, particularly where concentration could lead to distortions to competitive market outcomes. A particular concern is the extent to which an investment may allow an investor to control the global supply of a product or service.

The Australian Competition and Consumer Commission (ACCC) also examines competition issues in accordance with Australia's competition policy regime. Any such examination is independent of Australia's foreign investment regime.

Other Australian Government Policies (Including Tax)

The Government considers the impact of a foreign investment proposal on Australian tax revenues. Investments must also be consistent with the Government's objectives in relation to matters such as environmental impact.

Impact on the Economy and the Community

The Government considers the impact of the investment on the general economy. The Government will consider the impact of any plans to restructure an Australian enterprise following an acquisition. It also considers the nature of the funding of the acquisition and what level of Australian participation in the enterprise will remain after the foreign investment occurs, as well as the interests of employees, creditors and other stakeholders.

The Government considers the extent to which the investor will develop the project and ensure a fair return for the Australian people. The investment should also be consistent with the Government's aim of ensuring that Australia remains a reliable supplier to all customers in the future.

Though the national interest is defined broadly, possible negative spillover effects of any specific investment on other industries are not explicitly considered.

2.2 A qualification of the national interest test: The guidelines used for this study

(i) Net economic benefit

The project should make a significant net benefit to cumulative economic activity over its life including the construction phase.

(ii) Significant medium-term benefits

In order to ensure that the benefits are not delayed beyond the living spans of a significant proportion of the current living population, at least one third of the net benefits should be achieved within the first 10 years of the life of the operations of the project.

(iii) Strengthening the skill base of the economy

The project should, net, strengthen the skills base of the economy as measured by the skill intensity of demand for labour.

(iv) There is a significant net impact on Government revenues

In order for the benefits of resources to be distributed to the broader community, Governments need a significant revenue base to distribution. Therefore, a necessary requirement would be that the discounted Government revenue from the project be greater than what would be achieved from an expansion in the general economy.

(v) Australia's economic security

One requirement here, in general terms, would be for the economy to be able to withstand negative economic shocks better than would have been the case in the absence of the project. Australia's relatively secure open economy is subject to shocks in the form of sudden and adverse movements in terms of trade (commodity prices) and the exchange rate. It is desirable, therefore, that the project should reduce the economic costs of adverse commodity prices and exchange rates.

(vi) Australian political security is enhanced

It is desirable that the project should not promote economic dependence on any particular trade partner or closely-allied group of partners.

2.3 The national interest evaluation: Its importance in optimising national benefits

The decision to allow an individual LNG project to proceed or not, in terms of the national interest test, would depend on whether or not the expected net economic, environmental and security outcomes are significantly positive. The project would only be allowed to proceed if it was deemed likely to yield greater national benefit compared to denial of approval.

In most cases, however, it will not be a simple case of a go/no go decision. The national interest evaluation process will frequently identify negative outcomes which can be remedied either by changes in the particular project or by more general policy changes, unrelated to the particular project, which will increase the benefits generated by the project. These complementary policies or other changes may change the status of a project from 'no go' to a strong positive national interest return, and will frequently include strategies to minimise the costs which the project imposes on other industries. A rigorous national interest evaluation process is therefore in itself an instrument to maximise national benefit.

2.4 The benefit indicator

After the design of the national interest evaluation framework, the next most important decision is the selection of the core indicator for evaluating net benefits. In general terms the benefit indicator selected should measure that part of the flow of production that is available to support expenditures in the national economy that directly contribute to welfare/happiness. In the absence of direct measures of welfare, it is usual to concentrate on the flows of funds available to citizens for expenditure on meeting their needs and wants. We are therefore seeking within the constraints of available data for a benefit indicator of sustainable consumption.

A range of indicators is commonly used when measuring the impact of an investment on economic activity, including:

- gross domestic product;
- gross national product (gross domestic income); and
- net national product (net domestic income).

The bracketed name is what the series is now called in the Australian National Accounts. The original names are retained in this study because they clearly signal that the indicators have the same status as GDP whereas the new names imply a lower status. Gross domestic product is the value added generated in a given jurisdiction, irrespective of where the income is distributed. Gross national product (gross domestic income) is GDP less that part of GDP that is distributed to foreign residents or companies in the form of interest, dividends and undistributed income. Net national product is gross national product less that part of value added that is allocated to depreciation expenses. The last is the most appropriate to use in evaluating the benefits of investments in the gas industry for two reasons.

- high foreign ownership in the industry (one of the three LNG export terminals currently under construction at Gladstone is wholly overseas owned and the other two are joint ventures with substantial overseas participation); and

- very high depreciation charges (the bulk of depreciation expense occurs in the first half of the project life and much of it is returned overseas to repay debt).

Because of overseas ownership and high depreciation, the GDP indicator gives a very misleading indication of the benefits of LNG plants.

Given a regard for national welfare, the benefit indicator on which all national interest evaluations should be based should be either net national product (net disposable income) or direct estimates of sustainable private and public consumption expenditure impacts, which can be approximated by consumption expenditure plus total taxation revenue. Both NNP and consumption plus tax revenue are reasonably good proxies for sustainable consumption. Accordingly, for this study, the benefit indicator is taken to be an average of the two measures, that is, the sum of NNP plus private consumption expenditure plus taxation revenue divided by two.

2.5 A probability approach needs to be built into the evaluation framework

A probability approach is required for this study and for testing the implications of a project's approval by regulators. For this study a range of parameters have to be quantified with values around which there is a great deal of uncertainty not only in terms of current settings but also what the values may be over a 20 to 30 year time horizon.

Regulators are able to assess more accurately current information in regard to particular projects if only for the reason that it will be contained in the supporting documentation required for the approval process. In terms of the future values of required parameters, this will require judgement based on the best available current information. In this case, it would be useful for regulators to adopt a probability approach which requires the explicit setting of the characteristics of the probability distribution around key parameters.

This also fits into the general bottom line reality of assessments. Because of uncertainty, the best that any national interest assessment can conclude is that "*on the balance of probabilities it is concluded that .....*". By specifying probability distributions of the key parameters that determine the overall outcomes, the degree of uncertainty surrounding a decision for a project to proceed or not, or surrounding the conditions imposed on project approval, can be communicated to the general public. This eliminates the need for regulators to have a non-transparent and flexible definition of how the national interest is to be assessed.

Further, it can be more difficult to interrogate modelling results, and minor differences in assumptions can lead to big differences in outcomes. This worry is blunted if a probabilistic framework is adopted since, if results are sensitive to certain parameter specifications, this will be indicated by a high probability distribution range around the bottom line evaluation indicators.

In the present study, all relevant data and relationships used in the calculations for the national interest evaluation are included to readers to cross check the conclusions.

2.6 The quantification of risk – the Trigen distribution

For this study the probability distribution selected to quantify risk is the Trigen distribution. This distribution is selected because its parameters are easily related to the conditions that the probability distribution is describing.

To apply a Trigen probability distribution five parameters have to be specified. They are:

(i) the lower bound of the parameter/indicator;

(ii) the mode value of the parameter/indicator;

(iii) the upper bound value of the parameter/indicator;

(iv) the probability that values less the lower bound values will be taken; and

(v) the probability that values less than the upper bound value will be taken.

The approach will be illustrated for perhaps the most important input indicator for this study which has a high level of uncertainty. This indicator is the total remaining identified and undiscovered reserves of natural gas. As shorthand, these reserves are often referred to as remaining reserves. Chapter 6 below nominates the lower bound and upper bound values based on the estimates of others.

Figure 2.1: Trigen probability distribution for remaining reserves

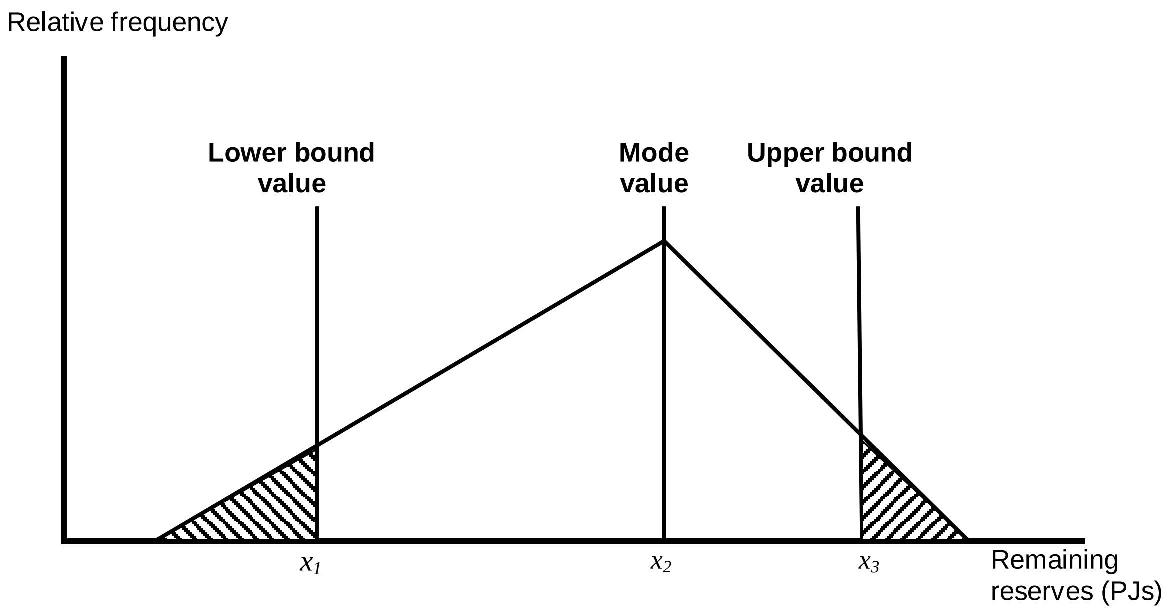


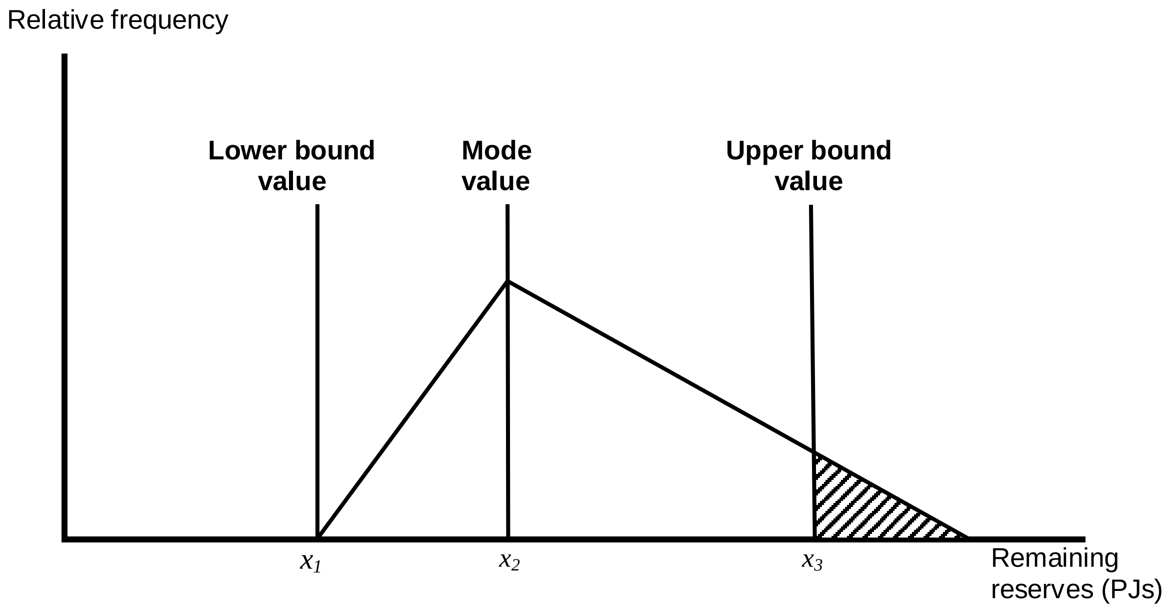
Figure 2.1 illustrates this case. Remaining reserves are measured in petajoules (PJs). The remaining reserves, in terms of lower bound (x_1), mode (x_2) and upper bound values (x_3) are selected on the best available information. If the upper bound probability is set at 100, then there will be no shaded area for the upper bound value. However, if it was considered that the probability of finding more reserves than the upper bound value, then the upper bound probability might be set at 80 per cent with the shaded area in the figure representing a probability of 20 per cent.

The same concepts apply to the lower bound values. For this study the lower bound probability is set at zero, meaning that there is no probability of the lower bound value taking lower values.

The mode can be selected on the basis of whether an upward or downward bias is to be imposed after consideration of upside and downside risks.

Figure 2.2 illustrates the case where the downside risks are considered dominant. Also, the lower bound probability is set at zero.

Figure 2.2: Trigen probability distribution for remaining reserves



2.7 The spillover impacts on other industries

A deficient national interest test would focus on the value of a project with little or no testing of the implications for other industries.

Comprehensive economic national interest testing examines how the project will impact other industries both positively and negatively. Comprehensive national interest testing, therefore, focuses not on the gross benefit of a project but the net impact after taking into account both negative and positive impacts on other industries.

3. LNG export expansion – channels of costs imposed on non-resource industries

LNG expansion can impose costs on other industries. Although a range of transmission channels may be relevant, the costs generally take the form of reductions in the level of output in other industries, sometimes referred to as crowding out. In a fully-employed economy some level of crowding out is inevitable if new projects are to proceed; the question is then whether the benefits from the new project exceed those lost through crowding out. In economies which are less than fully employed opportunities may exist to resource the new project without crowding out, in which case the potential benefits are considerable. However, there is also a possibility that projects will be implemented in ways which cause unnecessary crowding-out.

The discussion here is in qualitative terms and takes LNG expansion as a particular case of resource industry expansion. Although agriculture is also a resource industry, in the context of this chapter the term exclusively applies to the resource extraction industry. In ABS terminology the resource extraction industry is called mining and includes all activities which extract subsurface mineral resources other than water.

3.1 Macroeconomic resource (labour) constraints: Non-resource industry crowding out

Macroeconomic resource constraints apply to any LNG project planned for an economy which would otherwise be operating with full utilisation of resources, or which would reach full resource utilisation in the event of the project proceeding. Full utilisation can apply in both the construction and production phases of the project, and may apply to the economy as a whole or to particular inputs or geographic areas. If the project is to divert inputs from other uses the following tests must return positive answers if the project is to yield net benefits at the national level. (The tests are specified in terms of labour, but can be re-phrased to apply to any other diverted inputs such as office space). The first test is relatively simple: gross product, real wages and Government tax per hour worked by marginal workers transferred into the project are greater than gross product, real wages and taxes per hour worked by marginal workers in the industries from which they are displaced. The second test recognises that labour displacement will be accompanied by a gradual process of capital displacement, particularly during the construction phase, during which capacity-enhancing investment in the non-resource industries will be crowded out by resource project investment. The second test requires that the foregone productivity-enhancing effects of the crowded out investment does not reverse the first test.

Though these tests are conveniently specified in terms of labour, it should be remembered that Australia has a long history of alleviation of labour shortages through increased immigration. The chief concern, therefore, has to be crowded-out investment.

3.2 The drivers of manufacturing expansion

Relative costs are important in the sense that manufacturing will contract if there is too great a gap between domestic and foreign costs of production. However, even if relative costs are comparable and Australian products have a price edge (as when the actual $A/$US exchange rate is below its Purchasing Power Parity level) manufacturing expansion still depends on producers' ability to gain a competitive edge by product differentiation in terms of the design, functionality, durability, etc. of their products. This requires years of lead time in research and development and marketing efforts and also requires time to finance innovation and new capacity involving the latest technology and so on. The efforts of a firm to adopt best practice production technology, innovate via research and development expenditures and develop new markets are all part of either achieving competitive edge product differentiation or identifying opportunities for greater exploitation of existing advantages.

In the typical manufacturing industry the individual producer creates or maintains a market while in the resource extraction industry the producer responds to the market. This is why differentiated product manufacturing is riskier than most other industries. An important aspect of this higher level of risk is that differentiated product manufacturers have to create their own finance for expansion whereas in resource extraction industries this finance is delivered by the market.

At the macroeconomic level the different drivers of the resource extraction industry versus manufacturing expansion can lead to a conflict between manufacturing expansion and equivalent resource extraction industry expansion that is unrelated to issues of national resource availability. This is because the higher terms of trade effect associated with resource extraction industry expansion crowds out manufacturing activity through exchange rate impacts. The converse negative impact on the resource extraction industry from manufacturing expansion is much weaker because manufacturing expansion does not influence the terms of trade.

The most important dynamic is one of cumulative causation. Success in sustained manufacturing expansion depends on an uninterrupted sequence of steps that are resourced adequately and are consistent with market requirements.

Periods of highly over-valued exchange rates associated with elevated resource extraction industry activity intensity are very destructive for manufacturing. This is because high relative costs, in conjunction with already high risks, lead producers to curtail or end new development initiatives. Research and development (R&D) is scaled back and capacity expansion and replacement decisions are postponed, which leads to producers falling further behind their competitors in other countries. When the period of elevated resource extraction investment ends and the exchange rate falls back to cost parity levels domestic competitors are too far behind to restart R&D programs or even, in some cases, to undertake the replacement investment required to ensure long term business sustainability. The same adjustment process occurs, though less severely in terms of the long run negative outcomes, for other trade-exposed industries such as differentiated agriculture, high value business services industries, tourist industries and export-oriented segments of the health and education industries.

In general, a floating exchange rate protects the resource extraction industry in both the expansion and stability phase of the resource price cycle. For manufacturing and other trade exposed industries, positive stimulus to growth mainly comes in periods of low resource prices and hence low exchange rates. However the strength of this positive stimulus to growth is likely to be weak under the following conditions:

(i) if the period of low commodity prices corresponds to a period of relatively low world growth and low expectations of future growth; and

(ii) if a history of high exchange rates during past mining booms has generated expectations of future episodes, leading potential investors to discount the benefits of a current relatively low exchange rate heavily when they calculate the expected future returns on investment. They will not expect the exchange to remain low for very long.

Repeated episodes of resource extraction industry expansion lead to expectations of increasing volatility and the requirement of high short-term returns on investment.

National interest testing of a project's impact on economic security should cover a number of components, including, inter alia trade dependency and resilience to economic shocks.

3.2.1 Economic security: Trade dependency

It is not in an exporting country's national interest to become over-dependent for its exports on any other country. Over-dependence means that if the importing country's economic prospects decline rapidly it will force a significant decline in economic activity on the exporting country. There is also a risk that such trade dependency might be used by the importing country to force political and economic decisions on the exporting country even when they are costly in terms of the latter's national interest.

3.2.2 Economic security and the national interest: Resilience to economic shocks

One of the economic security components of national interest evaluation is the resilience to economic shocks test. If project proceeds, the project should not increase the security risk of the economy to a negative economic shock and, in particular, an exchange rate shock.

The one thing that is certain about any period of strong expansion in resource development is that it will end. More often than not the ending will be characterised by a rapid fall in commodity prices, closely followed by a fall in the exchange rate. This will lead to a widening of the current account deficit which in the Australian case is likely to be unsustainable given that, even with relatively high terms of trade, Australia's current account deficit is likely to be around 5-8 per cent of GDP circa 2016-2020.

The national interest evaluation would require that the following questions be answered.

(i) What is a plausible lower limit for commodity prices at the end of the current resource extraction industry expansion?

(ii) Assuming that the exchange rate falls in proportion to the commodity price fall, what would be the direct impact on:

- domestic inflation rates; and
- the current account deficit?

(iii) How much will national economic activity have to contract to return the inflation rate to desired levels? (The assumption here is that increases in unemployment rates are required to reduce the rate of growth of nominal wages and hence of costs and prices.)

(iv) In terms of (iii), does the project under consideration increase or reduce the contraction in economic activity necessary to bring inflation under control during a period of falling exchange rates?

(v) To what extent are import and export responses to the exchange rate devaluation likely to reduce the initial current account deficit after a reasonable time, say three years? What will be the contribution of the project to these responses?

(vi) Given the outcome of (v), what is the contraction in output required to restore the current account deficit to sustainable levels?

(vii) Given the outcome of (vi) does the go-ahead of the project under evaluation add to or reduce the contraction in economic activity required to restore the current account deficit to acceptable levels?

The national interest test would then compare the calculations from (iv) and (vii). If one or both answers were negative the project would fail the national interest test because it reduced the resilience of the economy to economic shocks. Failure of these tests means that the project could increase the contractions in the level of general economic activity required to achieve satisfactory inflation or balance of payments outcomes during the last phase of an episode of elevated resource expansion, the period of the return to stability.

3.3 Microeconomic resource constraints: Industry crowding out

As distinct from macroeconomic resource constraints, microeconomic resource constraints, resulting from projects proceeding, can impose costs on specific industries by limiting the growth in, or reducing the availability of, key resource inputs which cannot be effectively substituted with other inputs. In this case the industries affected have no option but to reduce actual or planned output in proportion with the actual or expected reduction in key input supply – a process which can easily lead to unemployment of other inputs.

For the case of LNG projects requiring large scale access to natural gas reserves, the impact on the future availability of gas will affect actual and expected investment, output and employment decisions in directly affected industries, especially heavy industry and electricity generation.

The chemical and alumina industries depend on the availability of gas at competitive prices. One or two LNG projects may not undermine confidence in the future availability of gas provided that expected gas reserves are adequate. However, with three and perhaps four additional LNG plants to come online over the next few years, along with projected expansion in the capacity of these plants, it is becoming clear that the combined claims on gas resources may lead to gas supply constraints in the eastern Australian gas market which will almost certainly lead to increasing expectations of real gas cost rises as higher costs of extraction are encountered in exploiting Australia's remaining resources of natural gas. The expectation of rising gas prices will reduce the willingness of producers in the chemical and alumina industries both to maintain the competitiveness of their current plants and to invest in additional capacity. This change in expectations could trigger a long-term decline in these industries which will be accelerated if expectations of gas shortages to domestic users take hold.

Because of the importance of the downstream gas-user industries in Australia's industrial structure and their recent growth performance, the impact of LNG export proposals on domestic users would have to be at the centre of any national interest evaluation for any valid determination of net project benefits. The critical indicator to focus on in this component of the national interest test is the ratio of annual natural gas demand (including all approved LNG plans) to estimated remaining reserves. If this ratio falls below acceptable levels then substantial microeconomic crowding out is likely to eventuate at some point over the project's life.

Microeconomic crowding out is analysed in Chapters 4 to 7 below.

3.4 Electricity price impacts

A further avenue of impact from LNG expansion lies in the implications for wholesale electricity prices that result from greatly elevated natural gas prices. Gas powered generation already plays a significant role in the electricity market, particularly in meeting peak demand, and its role is expected to grow both to provide backup to variable renewable generation and to provide relatively low-emissions base load. At peak times highly responsive Open Cycle Gas Turbines (OCGT) frequently set the wholesale price in the National Electricity Market and increased fuel costs can be expected to flow directly through to higher prices in that market. A 2010 AGL study found a $35 per megawatt hour difference in the marginal running costs of OCGT between a gas price scenario of $3.60 per GJ and one at $6.75.[2] These increases will flow through to almost all consumers, while those businesses who have moved to insulate themselves from rising electricity prices by installing highly efficient gas-fired cogeneration systems in recent years will find themselves subject to the same fuel price pressures.

[2] Paul Simshauser, Tim Nelson and Thao Doan, *The Boomerang Paradox, Part 1* (October 2010) http://www.aglblog.com.au/wp-content/uploads/2010/10/No.17-Boomerang-Paradox-Final-Oct-20101.pdf.

4. The natural gas usage trade-off: Domestic allocation versus export use – the case of natural gas dependent industries

Central to the application of the national interest test will be the direct economic value of a given quantity of natural gas from LNG exports versus the economic value of the same quantity of gas produced from domestic use. The net value of this comparison is a key estimate because:

(i) it indicates the cost of supply shortages if the export of gas has supply preference over domestic users; and

(ii) a high economic value for gas for domestic use entails that it is in the national interest that confidence in the adequacy of future domestic gas supplies at competitive prices ought not to be undermined by inappropriate exports.

The value of the trade-off will be assessed from two perspectives, namely:

(i) gas dependent industries; and

(ii) the non-resource economy excluding agriculture and mining.

The case of natural gas dependent industries is considered in this chapter and the broader economy-wide industry effects will be considered in the next chapter.

Natural gas dependent industries are industries where a large part of total output depends on the availability of natural gas at relatively low prices. These industries are the chemical sector and the non-ferrous basic metals industries (particularly alumina production).

To calculate the net value trade off for a given quantity of natural gas we estimate the value of current output of these industries that, in the long-term, would be curtailed if the supply of natural gas to these industries ended, or alternatively if supply was available only at such prohibitive prices that the industries became uncompetitive and retreated offshore.

4.1 Natural gas dependent industries: The direct value of natural gas availability

The chemical sector consists of the following major industries:

- basic chemicals;
- paints;
- pharmaceuticals;
- soap and detergents;
- cosmetics;
- other chemicals;
- rubber products; and
- plastic products.

There are other industries where the dependency on natural gas is high enough to justify the assumption that a substantial part of these industries, in the current environment, would not exist without reliable supplies of natural gas at competitive prices. These industries include glass and cement. The electricity sector is also becoming dependent on natural gas for peak power generation and increasingly for base load; this dependence will likely increase with the growth of renewables. The concentration of the present study on non-ferrous metals and chemicals to assess the cost of diversion of gas to LNG exports does not imply that other industries are unaffected. As long as the other affected industries have smaller economic values for gas the marginal cost of gas diversion is determined by the analysed industries.

The assumption in this study is that if natural gas was no longer available, the bulk of the basic chemicals industry would cease to operate, not necessarily overnight, but over time. The basic chemical industry was established in Australia before adequate supplies of natural gas became available. However, this was driven by factors including security objectives arising during and from World War II and high levels of tariff protection and subsidies. These no longer exist. More importantly, it was established at a time when other countries with large scale chemical industries also had limited or no supply of natural gas. The widespread availability of natural gas over the last half century has meant that the technological base of the industry has changed radically so that now a world competitive industry perforce relies on natural gas.

Other industries in the chemical sector rely on the presence of a local basic chemicals industry at the head of their supply chain and part of these industries would not exist without the availability of domestic basic chemical products. Accordingly the basic chemical industry generates a supply multiplier through the rest of the chemical sector. The question is how big is this multiplier effect? This multiplier effect was estimated by the following steps:

(i) using input-output table $m flows to calculate the share of product from the basic chemical industry used in the other seven chemical industries listed above as a percentage of output of each industry;

(ii) find the industry with the highest share of basic chemical products and nominate that share of this industry that would not exist in the long-run without the local availability of supply from the basic chemical industry. This nomination is termed the maximum basic chemical industry dependency ratio;

(iii) extend this nomination to the other chemical industries dependent on the basic chemical industry as the maximum basic chemical industry dependency rate multiplied by the basic chemical input share of the industry being estimated, divided by the basic chemical industry input share from (ii), or for that industry with the maximum basic chemical industry dependency ratio;

(iv) divide the results from (ii) for each industry by the basic chemical sector industry; and

(v) sum the results of (iv) across all the chemical industries to give the basic chemical industry multiplier, with a multiplier of unity for the basic chemical industry itself.

Table 4.1 gives the results of the calculation for Australia in 2008-09. The highest input ratio is for the plastics industry and the maximum basic chemical dependency ratio for this industry is nominated at 60 per cent. From this flows the multiplier estimates by industry shown in the second column of the table. The total multiplier value is 1.6.

Table 4.1 The chemical industry basic chemical multiplier		
	Input from basic chemicals – ratio of output	**Basic chemical sector – output multiplier**
Basic chemicals	0.12	1.00
Paints	0.05	0.02
Pharmaceutical products	0.01	0.04
Soap and detergents	0.06	0.01
Cosmetics	0.06	0.01
Other chemicals	0.07	0.07
Rubber products	0.02	0.01
Plastic products	0.13	0.44
Total	**–**	**1.60**

4.1.1 The importance of the local supply chain

It may be asserted that Australia's non-basic chemical enterprises would be best served by securing basic chemical inputs from anywhere in the world so long as they are at lowest cost and that a local basic chemicals industry is therefore not important. This view is wrong. The benefits of the local supply chain come from:

(i) just-in-time manufacturing capability;

(ii) manufacture of product that is required by the particular production technologies and product types produced by the local industry (these are not fully available elsewhere in the world);

(iii) security of supply; and

(iv) mutual dependency placing upper limits on price settings.

In this context, the multiplier value of Table 4.1 could be considered as being too low.

4.1.2 The non-ferrous metals industry

The non-ferrous metals industry consists of the alumina, aluminium and other processing industries, such as zinc, nickel, etc. Most certainly the alumina industry would not exist without the availability of natural gas, and almost certainly part of the aluminium industry would not exist without the availability of a strong local supply chain extending from bauxite to alumina and finally to aluminium.

Accordingly, the assumption adopted here is that half the Australian non-ferrous basic metals industry would not exist without the availability of plentiful natural gas supplies at reasonable prices.

4.1.3 Natural gas dependent industries: The direct value estimates

Given the above methodology, Table 4.2 profiles the direct benefit Australia receives from the supply of natural gas to the local gas-dependent industries. The estimates are in terms of $m of output per petajoule (PJ) of natural gas input.

Table 4.2	The direct benefit to Australia per PJ of natural gas – natural gas dependent industries (2008-09)
	$m
Non-ferrous metals	
Output per PJ	476
Adjusted output per PJ	238
Chemical sector ($m per PJ)	
Basic chemicals	168
Paints	3.9
Pharmaceuticals	4.0
Soaps and detergents	6.4
Cosmetics	2.2
Other chemical products	11.6
Rubber products	1.6
Plastic products	73.9
Total	**271.6**
LNG exports	**11.5**

The total value of a PJ of natural gas into the basic chemical industry, given the spillover benefits from the other industries, comes to $271 million per PJ. This is in accordance with the 1.6 multiplier developed above for the chemical sector.

The PJ value for LNG exports over the fiscal years from 2009 to 2011 has averaged $11.5 million. It is extremely important to recognise that this exported gas was sourced without affecting supply to domestic industrial users. The trade-off ratio means that if 1 PJ is instead shifted from local use by gas-dependent industries to export, the result is a direct loss of gross output of (averaging the basic metals and chemical sector estimates) of $255 million, compared to a $12 million gain from export revenues. The direct net loss in Australian value added is $243 million, or a loss/benefit ratio of 21 to 1.

This by itself would justify a national interest evaluation methodology which investigates whether local industry has an adequate supply of gas for the next two to four decades and approves LNG plants only when they can be supplied without affecting supply and price to domestic users. The fact that this evaluation is so compelling suggests that no such evaluation has been applied in national interest assessment to date. However, to be secure in this conclusion a further analysis needs to be undertaken, placing the direct estimates in the context of an input-output framework for the total national economy, incorporating into the analysis parameters reflecting differentials in the depreciation rates, tax rates and foreign ownership rates between industries, and assessing the net impact on the indicators selected as appropriate for national interest evaluations.

4.2 The input-output modelling framework

To evaluate the issue further, it is necessary to adopt a mixed demand-supply constrained input-output framework. This is because the existence of gas dependent industries means that these industries' activity levels are determined not simply by demand, but by whether or not there is an adequate supply of natural gas at reasonable prices to support domestic supply expansion where this is required to accommodate an increase in demand.

Let x_i represent (gross) output of industry i.

The economy consists of n industries, of which m industries are supply constrained by the availability of natural gas. By supply constrained is meant that they cannot automatically respond to demand changes unless the natural gas industry decides to provide the required inputs of (in this case) natural gas without major price increases.

The input-output relationship for the case where no industry is constrained is:

$$
\begin{aligned}
\begin{pmatrix} x_1 \\ : \\ x_m \\ \ldots\ldots\ldots \\ x_{m+1} \\ : \\ : \\ : \\ : \\ x_n \end{pmatrix}
&=
\begin{pmatrix} a_1 & \ldots\ldots & a_{1,m} \\ : & & : \\ a_{m,1} & \ldots\ldots & a_{m,n} \\ \ldots\ldots\ldots & \ldots\ldots\ldots & \ldots\ldots\ldots \\ a_{m+1,1} & \ldots\ldots & a_{m+1,n} \\ : & & : \\ : & & : \\ : & & : \\ : & & : \\ a_{n,1} & \ldots\ldots & a_{m,n} \end{pmatrix}
\begin{pmatrix} x_1 \\ : \\ x_m \\ \\ x_{m+1} \\ : \\ : \\ : \\ : \\ x_n \end{pmatrix} \\
&+
\begin{pmatrix} c_1 & \ldots\ldots & c_{1,n} \\ : & & : \\ : & & : \\ c_{m,1} & & c_{m,n} \\ c_{m+1,1} & & c_{m+1,n} \\ : & & : \\ : & & : \\ : & & : \\ : & & : \\ c_{n,1} & \ldots\ldots & c_{m,n} \end{pmatrix}
\begin{pmatrix} x_1 \\ : \\ : \\ x_m \\ x_{m+1} \\ : \\ : \\ : \\ : \\ x_n \end{pmatrix} \\
&+
\begin{pmatrix} f_1 \\ : \\ : \\ f_m \\ f_{m+1} \\ : \\ : \\ : \\ : \\ f_n \end{pmatrix}
\end{aligned}
$$

Given that x_1 to x_m are constrained, the (4.1) can be rewritten as:

$$
\begin{pmatrix} x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ x_n \end{pmatrix}
=
\begin{pmatrix} a_{m+1,1} & \cdots & a_{m+1,m} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ a_{n,1} & \cdots & a_{n,m} \end{pmatrix}
\begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}
+
\begin{pmatrix} a_{n+1,m+1} & \cdots & a_{m+1,m} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ a_{n,m+1} & \cdots & a_{n,n} \end{pmatrix}
\begin{pmatrix} x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}
$$

$$
+
\begin{pmatrix} c_{m+1,1} & \cdots & c_{m+1,m} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ c_{m,1} & \cdots & c_{n,m} \end{pmatrix}
\begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}
+
\begin{pmatrix} c_{m+1,m+1} & \cdots & c_{m+1,n} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ c_{n,m+1} & \cdots & c_{n,n} \end{pmatrix}
\begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}
+
\begin{pmatrix} f_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ f_n \end{pmatrix}
$$

Or in matrix form:

$$\boldsymbol{x}^{\boldsymbol{u}} = \boldsymbol{A}^c\boldsymbol{x}^c + \boldsymbol{C}^c\boldsymbol{x}^c + \boldsymbol{A}^u\boldsymbol{x}^u + \boldsymbol{C}^u\boldsymbol{x}^u + \boldsymbol{f}^u$$

Where:

$$\boldsymbol{x}^{\boldsymbol{u}} = \begin{pmatrix} x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ x_n \end{pmatrix}$$

$$\boldsymbol{x}^{\boldsymbol{c}} = \begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}$$

$$\boldsymbol{f}^{\boldsymbol{u}} = \begin{pmatrix} f_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ f_n \end{pmatrix}$$

A^c = $(n - m) * m$ matrix of coefficient of inter-industry input-output coefficients.

A^u = $(n - m) * (n - m)$ coefficients of inter-industry input-output coefficients.

C^c = $(n - m) * m$ matrix of consumption output coefficients for constrained industries.

C^u = $(n - m) * (n - m)$ matrix of consumption output coefficients for unconstrained industries.

Unconstrained industry output is, therefore, given by:

$$\mathbf{x^u = [I - A^u - C^u]^{-1} [A^c + C^c] + [I - A^u - C^u]^{-1} f^u}$$

Other indicators

Other indicators are given by the general form:

$$i_{o,j} = va_j \,.\, i^c_o \, x_j$$

Where:

$i_{o,j}$ = other indicator value (net national product, wage, salaries and mixed income, etc.) for industry j.

va_j = share of value added at factor cost to total gross output for industry j.

i^c_o = ratio of indicator o to value added (or gross surplus) for industry j.

x_j = total gross output for industry j.

The aggregate value across industries is given by:

$$i^t = \sum_{j=1}^{n} i_j$$

The key coefficients, i^c_o, are presented in Appendix B.

4.3 The input-output tables

The direct allocation of imports input-output table used for this study for 2008-09 is given in Appendix B. Other associated tables used are:

(i) the flow table with indirect allocation of imports;

(ii) the indirect tax flow table;

(iii) the import flow table as the difference between the Appendix B table and the indirect import table described in (i).

The key coefficients, tax, income, etc. by industry are also given in the table in Appendix B.

Adjustments are made to the coefficients given in Appendix B to better reflect the East Coast LNG industry as distinct from the offshore Western Australian industry, which is the only LNG industry reflected in the 2008-09 input-output tables. The main adjustment is to employment. The East Coast LNG industry is likely to be more labour intensive in operation due, in part, to its reliance on a land-based, dispersed natural gas collection and distribution system. As a result, the employment to output ratio is set at 0.19 or 60 per cent greater than the Western Australian average. Appropriate adjustments are made to other related parameters.

The foreign ownership ratio is also likely to be lower than for Western Australian projects. The average foreign ownership ratio for Queensland projects is set at 30 per cent.

The other issue is the tax rate. Once the Resource Rent Tax (RRT) becomes operational the ratio of direct tax to gross surplus will approach 50 per cent. However, this will not occur until towards 2030. In the early years, the tax rate will be negligible, rising to around 15 to 20 per cent once company tax rates become applicable. One way to account for this is to adjust the tax rates year by year, requiring all results to be presented in cumulative discounted terms only rather than as yearly average impacts. Accordingly, the tax rate is set at its average project level of around 35 cents in the dollar of gross surplus, which gives a significant upward bias to the benefits of LNG in the first half of a project's life.

4.4 The impact on the economy of LNG exports – a 50 PJ expansion

The model framework developed above will be used to assess the impact on the economy of a 50 PJ (approximately one million tonnes) LNG export expansion supplied at the expense of supply to domestic gas-dependent industries. The construction impacts are not considered.

In 2008-09 dollars, the additional gross output of LNG (and exports) comes to $620 million. Table A.1 indicates that GDP at market prices increases by $729 million, implying a standard multiplier of 1.2. However, the increase in net national product is half the increase in GDP. The increase in the benefit indicator is $401 million annually.

4.5 A 50 PJ contraction in natural gas supply to natural gas dependent industries

The second column in Table A.2 assumes that the 50 PJ expansion allocated to the LNG project is diverted from natural gas dependent industries. The reduction in gross output for the constrained industries given in Table A.2 runs to $12.8 billion in 2009 prices. This follows directly from the calculations given above on the assumption that 25 PJ is withdrawn from the non-ferrous metal industry and 25 PJ from the basic chemicals industry.

In this case the annual average loss in GDP at market prices is $11.0 billion, while total employment falls by 203,000 from what otherwise would have been the case. From column three of Table A.2 the gross negative from the natural gas withdrawal from natural gas dependent industries so overwhelms the positive impacts of LNG expansion that the net change between the two cases is close to the negative impacts of the gas withdrawal case for gas dependant industries.

The net (LNG plus gas dependant industry) cumulative discounted benefit indicator outcome is -$100 billion. The cost benefit ratio for gas withdrawal increases to 24.2 to 1, which may be compared with the preliminary estimate of 21 to 1 calculated in Section 4.1.3 above. Far from reducing the burden, placing the two cases in the broader context of the national economy increases the net cost of shifting gas from gas-dependent industries compared to LNG export expansion.

4.6 Conclusion

When natural gas is reallocated to exports from domestic use in gas-dependent industries, for every $1 of benefit gained from exports $24 of benefits is lost in contraction of the gas-dependent industries. This can be stated in discounted terms. In 2009 140 PJ of natural gas was allocated to Australian gas-dependent industries. It would have taken 3,400 PJ of LNG exports to deliver this benefit. If, at full development, the Australian east coast LNG industry is supplied at the expense of domestic gas-dependent industry, it will deliver less than a third of the benefit required to offset the loss of domestic industry.

On the other hand, the domestic gas using industrial sector does not put a significant claim on the supply options for Australian LNG and thus the growth options for LNG are not significantly constrained by domestic needs at present. However, this will change if large demands are made on gas as a transitional fuel to renewables.

The core issue is whether the large scale export of gas will constrain the ability of the domestic industry to expand or even maintain existing production levels. This will be considered in Chapter 6. In Chapter 5 we generalise the calculations of the present chapter.

5. The net benefits: LNG exports versus domestic gas use – the case of the general economy

One way to assess the impact of switching natural gas from domestic to export sales on the general economy, that is the non-resource sector of the economy, would be to use a large scale multi-sector model of the economy with detailed industry energy demand equations. Energy prices in general and natural gas prices in particular could then be adjusted until domestic natural gas use was reduced to required levels and the impact on the macroeconomic indicators assessed.

NIEIR has such a model and has used it for similar exercises many times. However, the model results are highly sensitive to model closure conditions. The final outcomes depend on which sector bears the cost adjustment for whatever the changed energy capacity arrangements have to be put in place to maintain overall demand/supply balance. From experience, the quantitative impact of the optimum strategy is approximated by a simple approach, which is adopted here.

The approach requires the direct estimation of a production function for the non-resource economy with capital, labour, gas and electricity as factor inputs. The estimated production function coefficients are then used to calculate the elasticity of substitution between gas and electricity. These two fuels are sufficient to specify the production function since, after the adjustment from the oil price shocks of the 1970s and early 1980s, the substitutability between natural gas and oil has been reduced to low levels. Effectively, gas now mainly competes with electricity.

A quantitative estimate of the elasticity of substitution between gas and electricity will enable the calculation of the quantity of electricity that must be supplied to leave economic activity unchanged after the withdrawal of domestic gas.

However, the economic adjustment does not end there. If the additional electricity supply can only be secured at significant additional cost, the additional costs on the economy will have to be taken into account. If these costs are allowed to flow into the industry structure of the economy there will be a whole range of flow-on effects, including loss of exports, increased imports and reduced real incomes. The least cost option (in terms of the fall in economic activity) is to channel the costs into the household sector with the major burden of adjustment being via real household incomes rather than by reduction in investment, exports, employment, and so on.

An alternative strategy would assume that there is no attempt to compensate for the loss of gas supply and non-resource gross product falls in line with the production function coefficient implications. This channel will also be evaluated in this chapter.

There is a third possible approach. This involves suppressing natural gas supply into the electricity sector which would force electricity production to exploit alternative and higher cost sources of supply. This lies outside the production function approach since natural gas input into electricity is included in the electricity input into the general economy.

These three alternative approaches are evaluated in turn.

5.1 The Australian production function

The task is to estimate a production function to determine directly the role of gas and electricity in driving Australia's economic activity. By definition it takes a supply side approach to economic activity.

A general production function can be written in the form:

$$Y \quad = \quad ae^{rt} (K, L, E, G) \tag{5.1}$$

Where:

Y = output, which may be defined as gross product of the economy, gross product of the private sector, or gross product of a combination of industries.

L = labour employed.

t = transport or total general government capital stock.

r = rate of exogenous technological change.

If a Cobb-Douglas production function is specified, then (4.1) becomes:

$$\ln Y \quad = \quad \ln a + rt + \alpha_1 \ln K + \alpha_2 \ln L + \alpha_3 \ln TE + \alpha_4 \ln G \tag{5.2}$$

where ln denotes natural logarithms.

The key estimate is for the a coefficient, or the elasticity of output with respect to gas input.

However, the Cobb-Douglas production function is restrictive in terms of the implied returns to scale for individual factors and the elasticity of substitution between factors. The latter is important for this study because of the requirement to use the elasticity of substitution between gas and electricity to obtain estimates of the costs of gas demand suppression.

To circumvent this, a flexible, that is, unrestricted, transcendental production function is estimated. This takes the form:

$$Y \quad = \quad Ae^{rt}\, ln^{\alpha 1}\, e^{b,L} \,.\, K^{\alpha 2}\, e^{b2K} \,.\, E^{\alpha 3}\, e^{b3E} \,.\, G^{\alpha 4}\, e^{b4G} \tag{5.3}$$

The two estimated coefficients which are of particular interest to this study are α_4 and b^4.

5.1.1 The data

Pooled time series cross section data are used to estimate the coefficients. The data is for the five mainland states. The period of estimation is from 1980 to 2011.

The output variable is state gross non-resource product (total state gross product at factor cost less gross product of agriculture and mining and ownership of dwellings. The annual data over recent years is from the Australian Bureau of Statistics (ABS) "*Australian National Accounts*", Cat. no. 5202.0. These estimates are spliced back to 1980 using estimates by NIEIR.

The labour input variable is total hours of work of the non-resource sector by state obtained from ABS "*Labour Force Australia*", Cat. no. 6203.0.

The methodology of estimating capital stock input by state for business capital stock and transport infrastructure capital stock is outlined in NIEIR's "*Transport Infrastructure Investment: An Instrument for Sustainable Debt Financed Fiscal Policy*", April 2012.

The energy data is taken from the Bureau of Resources and Energy "*Economics – data base for energy consumption by state and industry*". The electricity sector energy input is excluded from the non-resource sector totals for electricity and natural gas.

To remove cyclical effects a five year moving average is passed through the data.

5.1.2 The production function: Coefficient estimates and implications

The estimated coefficients are given in Table 5.1. Ignoring the constraints, non-zero coefficients are of the correct sign and, bar one, strongly significant.

A sensitivity analysis was used to calculate the elasticity of substitution between gas and electricity input and the elasticity of non-resource gross product for the four Eastern Australian mainland states. The elasticity of substitution, as at 2011, was calculated as -0.67. This means that if one PJ of natural gas is withdrawn from Eastern Australian markets, it will require an increase in supply of 0.67 PJ of electricity to maintain a constant level of non-resource gross product.

The elasticity of non-resource gross product at factor cost, with respect to natural gas input for the four Eastern Australian mainland states, was found to be 0.082.

Table 5.1 Estimated coefficients of the transcendental production function

Parameters	Coefficient	t-value
α_1	0.455	9.9
b_1	0.00000015	1.4
α_2	0.483	10.6
b_2	-0.0000067	10.1
α_3	0.011	0.6
b_3	0.103	3.2
α_4	0.0	–
b_4	0.00088	7.6
NSW constant	-0.428	0.8
VIC constant	-0.609	1.1
QLD constant	-0.653	1.2
SA constant	-0.615	1.2
WA constant	-0.803	1.6
$R^2 = 0.985$		

5.2 General economy adjustment to domestic suppression of 50 PJ of natural gas – the electricity substitution case

The three self-contained cases for the adjustment of the general economy to the suppression of 50 PJ of natural gas will be examined in terms of their impact on the economy using the framework applied in the previous chapter.

The elasticity of substitution between natural gas and electricity estimated above suggests that if 50 PJ of natural gas are withdrawn from the domestic market, 34 PJ of electricity will be required to maintain production capacity. The substitution would be partially focussed on space and water heating and process heat involving drying and melting.

Table 5.2 indicates that a considerable cost differential currently exists between electricity and gas, depending on the market and the carbon price. This means that total direct costs of adjustment will depend on the carbon price and a scenario analysis is therefore needed. This will be undertaken in Chapter 7 below. To illustrate the impact on the economy, in terms of the analysis of the previous section, a $50 price of carbon will be assumed. The data in Table 5.2 includes all transmission and distribution costs. The analysis here is for ex-plant costs.

Table 5.2 Current electricity and gas prices in Australia: The impact of carbon prices

	Electricity price	Gas price
No carbon pricing		
Industrial	$100/MWh = $28/GJ	$10/GJ
Residential/commercial	$250/MWh = $69/GJ	$16/GJ
Carbon pricing – $25/t CO_2e		
Industrial	$125/MWh = $35/GJ	$11.8/GJ
Residential/commercial	$275/MWh = $76/GJ	$17.8/GJ
Carbon pricing – $50/t CO_2e		
Industrial	$145/MWh = $40/GJ	$13.3/GJ
Residential/commercial	$295/MWh = $82/GJ	$19.3/GJ

5.2.1 The net cost of electricity substitution

It is critical that the same model framework be used for all evolutions of the possible adjustment paths for gas suppression. The framework developed in the previous section is ideal in terms of transparency and assessing the plausible impact of the contraction in gas dependent industries. For the more general adjustment paths of this chapter, other evaluation approaches are possible, but these would result in unacceptably different methodologies for quantifying impacts. Accordingly, the methodology used for calculating impacts in the electricity substitution case has been designed so that the modelling framework of the previous chapter can be employed. This framework also allows the straightforward introduction of probability analysis. The result is that the shock which is imposed on the model structure becomes a direct adjustment to real household disposable income.

It should be noted that no allowance has been made for the impact on distribution margins. It is assumed that the same total margins have to be recouped to support the distribution infrastructure installed, irrespective of throughput. In any case, the reduction in gas distribution margin would be offset to some extent by the increase in electricity margins.

These preliminaries out of the way, we proceed to model the full electricity substitution case. In the absence of the East Coast LNG plants, the industrial gas price will be taken to be $6/GJ. For each $10 of carbon price the cost of natural gas increases by $0.72/GJ, so the alternative gas price is $9.6/GJ. Therefore, the forgone cost of natural gas will be 9.6 x 50, or $480 million in 2009 prices.

Assuming that between 2012 and the 2020s there is increasing public and international anxiety about the baleful consequences if CO_2 emissions are not curbed, and therefore increasing political and economic pressure to reduce CO_2 emissions, the alternative electricity substitution cost will be taken to be an average of renewable options, for which recent cost estimates range from wind at $110 MWh to solar at over $200 MWh, with other renewables such as geothermal between the two polar cases. The average will be set at $150 MWh. This translates into $42 million additional cost per PJ, or $1.43 billion for the 34 PJ of electricity required.

The net cost is, therefore, 1.43 – 0.48 = $0.95 billion in 2009 prices annually.

To minimise the loss of employment and economic activity, the optimum cost allocation strategy would be to channel the impact into additional cost imposts on the household sector. This would hypothetically be done by:

(i) increasing direct taxes on households to pay for subsidies to shelter industry from the additional energy costs;

(ii) increasing residential electricity prices more than prices for non-household users; and

(iii) increasing the costs of electricity for those commercial sectors that service the household and Government sectors rather than trade-exposed industries.

The results of doing this for the full electricity substitution case are given in Table A.4 to Table A.6.

For the gross product indicators the impact is positive being about two thirds of the LNG overall impact. The combined total impact is a strong $1199m at factor cost. For net national product the increase is much less because of the high depreciation rate for the electricity sector. More importantly private consumption expenditure falls by $810m, or a net $646m if the LNG impact is included. The benefit indicator falls by $423m, more than cancelling out the gain from LNG exports. Full electricity substitution therefore results in no net benefit from LNG exports. The strong response for gross product is due to the fact that the drivers of this growth are dominated by factors (foreign income and depreciation allowances) which cannot be used to support domestic consumption and tax growth.

5.3 General economy adjustment to domestic suppression of 50 PJ of natural gas: The decline in economic activity case

Rather than release gas for export by switching to electricity, it would be possible to release the gas by reducing industrial activity. It is implausible to assume that all the natural gas suppression will involve reductions to industry; part will come from reductions in allocation to households. In the case here it is assumed to be 30 per cent of the total reduction impacts directly on households at a cost similar to the electricity substitution.

This still leaves 35 PJ to be suppressed from the non-resource industries. For the Eastern Australian market this will represent a 7.6 per cent reduction in supply. Using the elasticity estimated above, this will generate a 0.6 per cent reduction in gross non-resource product which translates into a $4.68 billion reduction in non-resource gross product at factor cost for the four Eastern Australian states. Using the relationship between direct reductions in household income and gross product at factor cost (see the model sensitivity results in the previous section) this indicates a direct reduction in household income of $3.58 billion. To this has to be added the reduction in real household incomes due to the transfer of 15 PJ of natural gas from the household sector to exports and its replacement with electricity. Using the full substitution case as the benchmark this will add $0.3 billion, bringing the total to $3.9 billion in 2009 prices.

Table A.4 shows the impact on the general economy for the general reduction in economic activity case. In terms of gross and net product, the decline in activity is six times the LNG benefit. The benefit indicator declines by 17 times the LNG benefit. Even if we make no particular allowance for gas-dependent industries and instead base the calculations on the non-resource sector as a whole, the outcome is decidedly unattractive.

5.4 General economy adjustment to suppression of 50 PJ of natural gas: The electricity sector gas substitution case

We now consider the case where gas is switched from the electricity sector to LNG exports. In this case, before the need for gas suppression, the 50 PJ of gas would have been used in the electricity sector to generate electricity. The scenario is that, in the absence of East Coast LNG exports, large scale gas-fired electricity plants would have been built near major CSM deposits and these exports require that the electricity sector will have to substitute other sources of electricity generation.

The two key determinants of the cost of this response are the cost of electricity generated from natural gas and the cost of the alternatives.

The cost of natural gas derived electricity will be a function of the natural gas price and the carbon price. Table 5.3 indicates a range of responses depending on the gas price and the carbon price. Assessing the effect of the carbon price involves modelling probabilities, because of the range of possibilities both for a given year and across time. This is carried out in Chapter 6 below. To illustrate the impact on the economy that is comparable to the approach taken for other adjustment paths above specific assumptions have to be made. The assumptions are:

- a price per gigajoule of $4; and
- a carbon price of $50.

From Table 5.3 this indicates an electricity price of $78 MWh.

As before, the alternative electricity price will be renewables at an average rate of $150 MWh. To complete the cost estimates it is necessary to know how much electricity can be generated from 1 PJ of natural gas. 1 PJ of electricity is 278 GWh. If a conversion factor of 0.45 is assumed, then 1 PJ of natural gas will generate 125 GWh of electricity. Hence, 50 PJ will generate 6,250 GWh or $489 million. If the alternative 6,250 GWh comes from renewables, then the cost will be 6.25 x 150, or $938 million, giving a net cost of $457 million.

Table 5.3 Natural gas based electricity – cost of supply by input costs

Combinations	Natural gas price ($/GJ)	Carbon price ($/tonne of CO_2)	Long-run marginal cost CCGT ($/MWh)
1	3	0	49
2	4	0	55
3	5	0	61
4	6	0	67
5	3	50	69
6	4	70	83
7	5	80	93
8	6	100	107
Alternative			**150**

Note: CCGT denotes combined cycle gas turbine. Assume 65 per cent capacity factor. For every $10 increase – carbon price a $/tonne of CO_2, the price will increase by $4/MWh. For every $1/GJ increase in the natural gas input price the $/MWh price increases by approximately $6 in 2009 prices.

The impact on the general economy of the gas suppression case is given in Table A.4. This is a low cost case compared to the decline in economic activity case but comes at a higher cost than the full electricity substitution case. For the gross product indicators, the decline is a little under 40 percent of the LNG benefit. However, there is a deterioration compared to the net product indicator with the loss from the gas suppression case almost cancelling out the gain from the LNG expansion. However for the benefit indicator the loss from gas suppression in electricity use is nearly 30 percent more than the LNG benefit.

It should also be noted that the suppression of gas supply to the electricity sector, or if suppression is avoided the increase in gas prices that will result from LNG netback pricing and production from higher-cost reserves, would ultimately have implications for the costs of all existing gas-fired generators. Operating costs for both peaking plants and CCGT would increase, driving higher spot and contract prices in the National Electricity Market.

The electricity sector gas suppression case is a relatively low cost option. Nevertheless the net costs are still significant.

5.5 Conclusion

Analysis which abstracts from the position of the gas-dependent industries concludes that natural gas can be switched from domestic sales to LNG export sales using a number of strategies, the best of which yields little benefit to the economy and the worst substantial net costs. In this worst case, the costs approach those calculated when concentrating on the position of the gas dependant industries. To minimise cost, the following factors would have to be put in place, namely:

(i) the natural gas dependent industries were quarantined from any impact of LNG expansion on available gas supplies and costs;

(ii) the electricity sector would have to plan to carry the full cost of adjustment including higher quantitative targets for renewable energy; and

(iii) the household sector would have to accept that it and not industry would have to directly accept the full costs of adjustment.

Historical experience, the current design of the policy for the introduction of carbon taxes and the political debate over carbon pricing give no grounds for businesses to expect that the minimum cost path would be adopted if it becomes necessary to withdraw domestic natural gas supply to meet export contracts.

How the four options may be combined to determine an overall gas suppression response is outlined in Chapter 7 below.

6. The Australian gas market: Resources, prices and risk of supply shortage by 2040

The prime objective of this chapter is to assess the risks of supply shortages in the Eastern Australian gas market by 2040. This is a critical final step to assessing the likelihood that the costs of natural gas supply withdrawal assessed in the previous two chapters will be realised. The risk of gas supply shortages emerging in turn depends on estimates of natural gas reserves remaining to be discovered.

6.1 The Australian natural gas market: Background

The Australian natural gas industry has three distinct components:

1. the domestic Eastern Australian system;
2. the domestic west/north coast systems; and
3. the LNG export industry (currently only on the west coast fed mainly from off-shore fields, with plants proposed for Eastern Australia based on coal seam methane).

As with electricity, there is no transmission connection between the east and west coasts (Tasmania is connected to the eastern gas and electricity transmission systems).

In 2012-13 total Australian gas production will be about 2,500 PJ, about 35 per cent of which will be exported as LNG. The main producing basins are: in the East, the Gippsland, Cooper-Eromanga and Otway (conventional); and the Bowen and Surat (coal seam gas); and in the West, the Carnarvon, Bonaparte and Browse.

In the domestic markets, east coast demands are about 800 PJs and west/north coast demands 650 PJs. The major domestic markets are for gas-powered electricity generation (GPG), industrial and residential consumption. The GPG market is growing most rapidly but future GPG increases depend significantly on carbon pricing policies.

The current CO_2e price of \$23/t CO_2e is not high enough to stimulate substantial growth in GPG for combined cycle gas turbine (CCGT) base load plants. Gas peaking plants are relatively unaffected by carbon pricing, being mainly responsive to growing summer peak loads where gas plants (open cycle gas turbines, OCGTs) have distinct quick response advantages. Growth in GPG base load will depend on carbon tax levels, gas prices, coal prices and any policy initiatives that directly favour gas (such as the Queensland gas generation policy).

In the industrial sector gas is used for process heat (drying, etc. such as alumina production), water heating, steam raising and for production of petrochemicals (such as ammonia). Metal products, petroleum and chemicals and non-metallic mineral products account for about 85 per cent of industrial gas consumption in Australia.

The alumina industry, a major use of gas for drying (often with cogeneration), is concentrated in south-west Western Australia (Kwinana region) and Gladstone in Queensland. In Western Australia, industrial gas prices have increased substantially (from \$4/GJ to \$8/GJ) due to domestic market supply/demand constraints and reliance (65 per cent) on the North West Shelf project (LNG predominantly) supply. In eastern Australia industrial gas prices are in the \$4 to \$6/GJ range, including network costs as well as wholesale gas costs. At higher prices (>\$10/GJ) some industrial gas users could lose competitiveness to competitors based in gas rich regions, such as the Middle East. Fertiliser and other chemical plants would be at risk, as would alumina.

Over 2011-25 NIEIR estimates (July 2012) growth in industrial gas use will average 2.91 per cent per year, residential 1.48 per cent, commercial 2.4 per cent and electricity generation 4.48 per cent per annum.

The major industrial market is in Western Australia (alumina, direct reduced iron and ammonium nitrate), 55 per cent of national industrial market. The major residential market is in Victoria (space and water heating), 65 per cent of national residential market. GPG is strongest in Queensland and Western Australia.

6.2 Estimates of reserves

Category 1 reserves (commonly referred to as 'Proven' or 'P1' reserves) include recoverable reserves that have been declared commercially viable. **Category 2** reserves (commonly referred to as "Probable' or 'P2' reserves) comprise estimates of recoverable reserves that have not yet been declared commercially viable, although they have been geologically proved or are awaiting further appraisal. Geoscience Australia (GSA) are now **mainly** using the McKelvey classification of economic and sub-economic demonstrated resources (EDR, SDR), but do not precisely define (for example, $/G) EDR and SDR. In addition, P3 possible/potential reserve estimates are sometimes estimated. Also, inferred resources are mentioned. These arise from recent discoveries and finds that require further appraisal.

While there is always some uncertainty associated with any reserves estimates, GSA's estimates are often regarded as conservative. These estimates should perhaps be seen as a lower bound estimate of actual reserves. Due to this conservatism, NIEIR formulates its own estimates of reserve levels in the eastern basins by supplementing official data with information recently published by operators and other basin participants. Over the years (1980s on) we have observed significant increases in GSA reserves towards NIEIR estimates.

West Coast (Western Australia/Northern Territory) reserves are mainly in off-shore basins (Carnarvon, Browse, Bonaparte) and amount to about (2009 data, no recent update) 165,000 PJ in P1 and P2 reserves (not including CSM or shale gas). Source: Geoscience Australia, Oil and Gas Resources of Australia 2008.

Eastern Australian reserves, from the same source, P1 and P2 reserves were about 11,000 PJ (excluding CSM and shale reserves); and P3 at 28,000 PJ. CSM reserves (P1, P2) were estimated at 37,000 PJ (P3 at 60,000 PJ).

McKelvey classification reserve estimates are outlined below. Source: Australian Gas Resource Assessment, 2012.

Table 6.1 Australian conventional gas resource represented as McKelvey classification estimates as of 1 January 2011

Conventional gas resources	PJ	tcf
Economic demonstrated resources	113,400	111
Sub-economic demonstrated resources	59,600	53
Inferred resources	11,000	20
Total	**184,000**	**184**

Table 6.2	McKelvey classification estimates by basin as at 1 January 2011		
		Gas	
McKelvey class.	**Basin**	**PJ**	**tcf**
EDR	Carnarvon	74,700	68
EDR	Browse	17,900	16
EDR	Bonaparte	10,100	9
EDR	Gippsland	7,000	6
EDR	Other	3,600	0
Total EDR		**113,400**	**103**
SDR	Carnarvon	26,800	24
SDR	Browse	17,900	16
SDR	Bonaparte	11,900	11
SDR	Gippsland	2,300	2
SDR	Other	1,200	1
Total SDR		**59,600**	**54**
Total (EDR + SDR)		**173,000**	**157**

CSM/G reserve estimates, not included above are presented below.

Table 6.3 CSG resources at January 2011		
CSG resources	**PJ**	**tcf**
Economic demonstrated resources	35,905	33
Sub-economic demonstrated resources	65,529	60
Inferred resources	122,020	111
Total	**223,454**	**203**

Table 6.4 Total Australian gas resources										
Resource category	**Conventional gas**		**Coal seam gas**		**Tight gas**		**Shale gas**		**Total gas**	
	PJ	**tcf**	**PJ**	**tcf**	**PJ**	**tcf**	**PJ**	**tcf**	**PJ**	**tcf**
EDR	113,400	103	35,905	33	–	–	–	–	149,305	136
SDR	59,600	54	65,529	60	–	–	2,200	2	127,329	116
Inferred	11,000	10	122,020	111	22,052	20	–	–	155,072	141
All identified resources	**184,000**	**167**	**223,454**	**203**	**22,052**	**20**	**2,200**	**2**	**431,706**	**392**
Potential in ground resource	Unknown	Unknown	258,888	235	Unknown	Unknown	435,600	396	694,488	631
Resources – identified, potential and undiscovered	184,000	167	258,888	235	22,052	20	435,600	396	900,540	819

Note: Conventional gas demonstrated resources as of January 2011; CSG demonstrated resources as of January 2012. Note CSG 2P reserves and 2C resources are used as proxies for EDR and SDR respectively.

Tight gas and shale gas resources

Currently Australia has no proven reserves of tight or shale gas. The in-place resources of tight gas are estimated at around 22,000 PJ (20 tcf) but together with shale gas could be considerably higher. The largest known resources of tight and shale gas are in low permeability sandstone reservoirs in the Perth, Canning, Cooper and Gippsland basins with APPEA's estimates at 440,000 PJ of total possible reserves

6.3 Total Australian reserves (identified, potential and undiscovered)

What is important for this study is not total Australian reserves, but reserves that can supply the integrated Eastern Australian market. This is the market that the East Coast LNG projects will impact. The situation would be different if the Western Australian market was integrated with the Eastern Australian market.

6.3.1 Two estimates of Eastern Australian case reserves

One recent attempt to estimate Eastern Australian reserves was carried out by **Core Energy Group** (COE): gas (Eastern Australian) resource studies, 2012. This study included a section on the distribution of gas reserves by gas production costs (COE page 24).

Core estimated a total of 143,066 PJs potential resource at 1 January 2012 at up to $6/GJ and about 161,000 PJs at up to $8/GJ.

In the report (Table 7.1) **conventional** resources were estimated to be 13,000 PJ at up to $7.37/GJ at a 10 per cent rate of return. In Table 7.2, **coal seam gas** reserves were estimated to be 96,000 PJ at up to $5.58/GJ at a 10 per cent return. In Table 7.3 estimates for total Eastern Australian **prospective** resources were given as 190,000 PJ at up to $9.27/GJ at a 10 per cent return.

The study also gave estimates of gas transmission costs as at April 2012. Indicative tariffs for **existing** pipelines are provided in this report in Table 6.4, page 12.

For **new** pipelines estimated tariffs are presented in **Figure 10.4** for a range of pipelines. For example, an estimated tariff of $0.0018/GJ/km for a 1,000 kilometre hypothetical pipeline would result in a tariff of $1.8/GJ for the full 1,000 kilometres of gas transmission. Estimated tariffs are also presented in **Figure 10.4** for a range of existing pipelines such as $0.0014/GJ/km for the Eastern Gas Pipeline. Tariff components (WACC, taxation, etc.) are also provided for several pipelines.

Another study which also estimates remaining gas reserves was by **ACIL Tasman**: draft report, December 2011, Fuel cost projections. This report was prepared for Worley Parsons to provide natural gas and coal outlooks for AEMO modelling.

ACIL Tasman estimated (page 6, Figure 3) that around 90,000 PJ of potential (reserves and resource) could be developed on the East Australian seaboard at up to A$8/GJ (of which 50,000 PJ is Queensland CSM); and 60,000 PJ (about 40,000 PJ of CSM) at up to $6/GJ. **Note** that in the same report ACIL Tasman estimated that in addition to these reserve estimates 25,000 PJ of Eastern Australian shale gas could be available at $9/GJ.

These estimates are much lower than the COE estimates outlined above. The reasons for estimate differences are difficult to discern from the two sets of reports, though COE allows for sales of liquids from gas projects, thus improving project economics.

Potential use of Eastern Australian reserves over 2012-2040 are presented below.

Table 6.5 Potential domestic use of Eastern Australian natural gas reserves

		2015 (NIEIR)	2025 (NIEIR)
Gas (2011, 1,300 PJ)	**Total**	1,400 PJ	2,300 PJ
	GPG use	416 PJ	986 PJ
	Excluding gas for power generation (GPG)	≈ 950 PJ	≈ 1,300 PJ
Electricity consumption	Total in NEM	200,000 GWhs	256,000 GWhs
	Australia	236,000 GWhs	311,000 GWhs

Potential GPG (electricity) use

A 400 MW CCGT	at 90 per cent capacity factor requires about	22 PJ/a
A 10,000 MW CCGT	at 90 per cent capacity factor requires about	550 PJ/a

Potential LNG export use

LNG	4 Mt plant requires 200 PJ/a	1 train
	20 Mt plant requires 1,000 PJ/a	5 trains

28 years (2012-2040) potential use

End use	Approximate average	1,700 PJ/a	= 47,600 PJ
10,000 MW GPG by 2040	Approximate average	300 PJ/a	= 8,400 PJ
LNG (6 trains by 2040)	Approximate average	800 PJ/a	= 22,400 PJ
			78,400 PJ

This suggests adequate availability at up to $8/GJ on the above assumptions: LNG use could be higher but GPG and end-use could be lower. Table 6.5 is the basis for the Eastern Australian market's natural gas projections for the case of no LNG plants outlined below.

6.3.2 Western Australia/Northern Territory

Domestic gas use

In 2012 Western Australia's total gas use is estimated at 617 PJ and Northern Territory at 43 PJ. Western Australia's gas use is dominated by industrial use (442 PJ) and GPG (145 PJ), growing respectively over 2012-25 at 2.65 per cent and 3.44 per cent average per year. Total use in 2025 is estimated to be 905 PJ, the increase mainly through alumina, direct reduced iron, ammonium nitrate and GPG expansion.

In the Northern Territory industrial (24 PJ) and GPG (19 PJ) dominate gas use, growing respectively over 2011-25 at an average per year of 8.4 and 7.0 per cent. Total use in 2025 is projected to be 122 PJ through increases in industrial use (Gove Alumina conversion to gas from fuel oil) and GPG.

Potential domestic use over 2012-2040

At an average annual use in the region (Western Australia/Northern Territory) at the 2025 level of 1,027 PJ, regional gas use over 2012-40 would be about 30,000 PJ. Use could be higher depending on GPG economics (carbon and gas prices) and industrial use (regional competitiveness in global markets).

Potential LNG use over 2012-40

LNG use of gas in the region (Western Australia/Northern Territory) will depend on global demands for LNG and competitiveness of regional LNG plants.

Global LNG demand is projected to increase significantly over the period depending on global climate change policies: aggressive policies could constrain global gas demands. Regional LNG competitiveness could be constrained by high regional costs for new LNG plants and global LNG competition from the Middle East, East Africa, North America and Europe. The strength of this competition will depend considerably on the success of Middle East and Russian gas export strategies and on global shale gas developments. At regional (Western Australia/Northern Territory) average LNG exports over 2012-2040 of 100 Mtpa (about 5,000 PJ per year) LNG exports would total 140,000 PJ.

Total requirements, reserves and prices: Western Australia/Northern Territory

On the basis of the above estimates, 170,000 PJ of regional gas would be consumed (domestic, LNG) over 2012-40, about the current estimates (P1, P2/EDR, SDR) of regional reserves (excluding CSM and shale, which are not yet prominent in the region).

No costs of reserve estimates for the region are available as far as we are aware. Based on net back estimates required for existing and proposed LNG projects, we consider the requirements could be met at <A$8/GJ (ex-processing plant) and <A$10/GJ delivered to customers.

6.4 Proposed LNG plants, 2012-18

Over the period to 2018, 12 LNG plants are proposed: 8 on the west coast (output 70 mtpa) and 4 on the Eastern Australian (30 mtpa). If all proposed plants proceed, gas use by the plants over the period to 2040 would be about 3,400 PJ/a and about 84,000 PJ in total on the west coast; and 1,500 PJ/a and 36,000 PJ in total on the Eastern Australian. (ABARE/BREE, 2010; 5,930 PJ **total** exports in 2029-30.)

Given the prices of gas from LNG in export markets and the cost of liquefaction, transport, regasification and transmission to pricing hubs, to be profitable we judge LNG exporters must be able to access gas at $6-8/GJ (the net back price) for existing and proposed LNG plants.

6.5 Gas prices: weighted average, 2007-08 to 2039-40 – the current view

Gas prices have not been historically transparent whether at the well-head, ex-processing plant or delivered, particularly for large users.

Preliminary estimates for weighted average gas prices (ex-processing plant) are set out below.

Table 6.6 Projection of natural gas prices

Year	Prices (2011-12 $/GJ)	
2007-08	$4	
2011-12	$5	
	Conventional view	**Alternative (optimistic) view**
2019-20	$9	$7
2029-30	$13	$10
2039-40	$15	$11

The alternative optimistic view is based on potential global trends in gas supplies and demands (climate change policies and gas technology improvements for exploration and development).

Traded gas prices, for example those used by ACIL Tasman for the AEMO scenarios, continue to be mainly based on the oil price/gas export price relationship which could be loosened resulting in lower gas prices as global gas competition increases. That is, we believe that despite its continued use in gas trade pricing, there is no longer a logical basis for this concept. Gas and oil are no longer significant substitutes in energy markets for electricity generation, space and water heating, etc. Exploration, development and marketing of the two commodities have diverged over the past 20 years.

6.6 Shale gas: A global gas revolution

The production of gas from low permeability gas rich structures has led to a transformation of the USA gas industry. Gas production from this source in the USA has risen from 4 per cent of total USA gas production in 2004 to 25 per cent in 2011, a total in 2011 of 5,650 PJ (twice Australia's 2011 production) with a reserve estimate (USA EIA) of 4.8 x 10^6 PJs. The flood of shale gas has dropped wholesale gas prices in the USA from >US$10/GJ in 2006 to >US$3/GJ in 2011-12 and stimulated investment in USA LNG export plants.

There is potential for the North American (Canada also has shale gas reserves) experience with shale gas to be repeated elsewhere, but caution is advised as conditions (geologic, development costs, environmental, infrastructure, politics) for shale gas development can vary widely.

In Australia there appears to be significant shale gas potential in the Cooper, Galilee, Perth and Canning Basins.

In North America viable/profitable wellhead prices for shale gas appear to be >US$5/GJ, so the industry is currently not profitable leading to a write-down of shale gas assets by companies (including BHPB). Of the majors, Chevron appears to be shale gas positive with Exxon-Mobil less so.

In a report on Fuel Cost Projections to provide outlooks/inputs for AEMO modelling, ACIL-Tasman in December 2011 estimated an aggregate shale gas resource of 25,000 PJs in eastern Australia at a cost of around A$9/GJ (2012-13 $'s). The report noted that this would tend to limit upward pressures on gas prices. It should be noted, however, that this upper limit, if realised, would still be twice to three times as high as previous wholesale prices.

6.7 The specification of the probability distributions

The above analysis for Eastern Australia needs to be incorporated into the analysis by the specification of probability distributions for two key parameters, namely the remaining reserves and the percentage of remaining gas reserves discovered by 2040.

Table 6.7 gives Trigen probability estimates for the two parameters. The lower bound estimate is the ACIL Tasman estimate. The upper bound estimate is the Core Energy Growth estimate plus the tight and shale gas reserves estimate. There is considerable upside in terms of shale gas availability. This is incorporated into the analysis by setting the upper bound probability relatively low at 85 per cent. This ensures that the maximum upper bound will be higher than the estimate set in the table.

The specification of the estimates of the per cent of remaining reserves at 2011 discovered by 2040 is straightforward and given in Table 6.7.

The reserve production trigger ratio requires explanation. It is one of the most important parameters in the analysis. The central assumption is that there is a minimum identified reserve to production ratio which, if attained, will render prohibitive the risks of investing in gas-intensive projects. This applies equally to new projects as it does to the investment to maintain the competitiveness of existing facilities. This trigger's value will vary from project to project and industry to industry. It is unlikely to be much lower than 15. Below 15 means that the risks are high that there will not be enough gas to feed the gas-using capacity currently installed. For large scale gas-using projects, the realised reserves to production ratio would have to be significantly above 15 given a three year construction period and a 20 to 30 plant life. Hence, the upper boundary is set at a reserve to production ratio of 25 in Table 6.7.

Table 6.7 The specification of the Trigen probability distribution parameters

		Unit	Lower bound	Mode	Upper bound	Lower bound probability	Upper bound probability
1	Reserves remaining as at 2011	PJ	90,000	163,000	237,000	0	85
2	Per cent of reserves remaining as at 2011 discovered by 2040	Per cent	55	70	80	0	95
3	Reserves – production ratio trigger for suppressing gas demand	No.	15	20	25	0	100

In the model, if Eastern Australia's gas reserve to production ratio falls below the trigger level, the new growth in demand ceases and normal replacement investments are not made, meaning that underlying demand will fall by 2 per cent per annum. The level of demand falls to regain the benchmark reserve to production ratio. If more gas suppression is required gas is suppressed in the electricity sector and finally, in the case of severe restrictions, there will be plant closures.

6.8 The outcomes for the Trigen distribution

Probability estimates from the Trigen distribution parameters specified in Table 6.7 are presented in Table 6.8. The table indicates that the maximum estimate for discovered and undiscovered reserves, as at 2012, is 263,400 PJ. There is a 75 per cent probability that 147,000 PJ will be discovered and a 25 per cent probability that at least 200,000 PJs will be discovered.

The extraction ratio by 2040 of discovered reserves rises from a 5 percentile rate of 60 per cent through a mean of 70 per cent to a 95 percentile level of 80 per cent.

Table 6.8	Reserves and extraction probabilities	
	Ultimately recoverable reserves (PJs)	**Per cent of reserves discovered by 2040 (%)**
Aggregate indicators		
Minimum	91288.86	55.35
Maximum	263437.80	84.62
Mean	173481.80	69.89
Std Deviation	36426.91	6.06
Distribution		
5% Percentile	115200.30	59.67
10% Percentile	125942.10	61.64
15% Percentile	134066.20	63.15
20% Percentile	140810.00	64.43
25% Percentile	146886.90	65.53
30% Percentile	152278.00	66.55
35% Percentile	157293.80	67.46
40% Percentile	161965.70	68.33
45% Percentile	166397.90	69.14
50% Percentile	171161.40	69.90
55% Percentile	176066.50	70.66
60% Percentile	181323.10	71.46
65% Percentile	186829.00	72.32
70% Percentile	192840.70	73.23
75% Percentile	199367.60	74.23
80% Percentile	206442.70	75.32
85% Percentile	214675.40	76.58
90% Percentile	224387.30	78.05
95% Percentile	236890.60	79.99

6.9 The cost of natural gas ex-plant

A price constraint is also inserted into the model. If prices exceed a benchmark level new growth in demand (including replacement demand) will cease. The price formula in the model is given by:

$$Pg = 5 + 0.15 \,.\, RD$$

Where:

Pg = price of gas ex-processing plant.

RD = per cent of reserves extracted as a per cent of remaining reserves, as at 2012.

The schedule has an upper limit of $15/GJ as the extraction ratio of estimated 2012 remaining reserves approaches its upper limit.

6.10 The base case: No Eastern Australian LNG plants

Given the model developed above, the base case will be the case of no Eastern Australian LNG plants to 2040. This will indicate the risk of suppressed demand for gas in the absence of the LNG projects proceeding. The results are given in Table A.7.

If there were no East Coast LNG plants, there is no chance of suppressed demand by 2020.

In the absence of the LNG exports from Queensland, there is only a very small chance, at the 95 percentile level, of the need for gas suppression in the 2020s.

In the 2030s there is a mean risk of the need for natural gas suppression but it is small, at 25 PJ per annum. This is on the basis that between 2025 and 2040 the Eastern Australian domestic natural gas demand grows at 2 per cent per annum for non-electricity sector gas use. The electricity sector case stays constant at the 2025 level to 2040.

6.11 The case of LNG exports

The alternative case is of the impact of 24 million tonnes of East Coast LNG exports on the Eastern Australian demand-supply balance. For the 2012-2020 period there is a mean expected outcome that the Eastern Australian domestic demand will be suppressed by an average of 40 PJ a year. For the 2020s the mean expectation is for a suppression of 600 PJs, with the 25 to 75 per cent probability range being between 165 and 952 PJs. By the 2040s the expectation (that is, the mean) is that there will be a suppression of natural gas equal to 40 per cent of the unconstrained demand case. The 25 to 75 per cent probability range is for a 2040 natural gas suppression rate of between 24 and 58 per cent.

Overall the mean expectation is that a cumulative 15,000 PJs of natural gas demand will be suppressed.

Table A.9 gives the net impact of the East Coast LNG exports on the domestic demand supply balance. As the results in Table A.8 demonstrate, there is little difference between the results in the two tables.

The tables enable readers to apply their own judgement. If one wanted to be optimistic, then the 30 per cent percentile case could be made equal to the expected case. In this case there is still a cumulative shortfall by 2040 of suppressed domestic natural gas demand of 7,640 PJs, with severe supply shortages appearing in the 2020s and the expectation that by 2040 the suppressed demand as a per cent of base case demand is 27 per cent.

6.12 Conclusion

The results are very significant. The results indicate that either the national interest evaluation of the LNG plants was deficient or that confidential knowledge of the gas resources available confirmed that these resources are considerably greater than what is in the public domain. Even if the latter is the case, impacts will not be avoided. There may well be adequate reserves but businesses make decisions on what they know and what they know would indicate that gas is likely to be transferred from domestic to LNG export sales. In this case the net economic cost of the East Coast LNG plants having preferred access to supply will involve very large costs on the economy.

The exact costs will be quantified in the next chapter.

7. The net benefit of East Coast LNG expansion in the context of Eastern Australian demand/supply balance

This chapter takes the results of the last three chapters and assesses the net national benefits and costs of the East Coast LNG expansion. In the event of limited supply to domestic users, the burden of adjustment will be divided between:

- gas dependent industries;
- general economy adjustment – decline in activity;
- general economy adjustment – full electricity substitution; and
- electricity sector gas suppression.

The key task in preparing input to the analysis is to specify the distribution of the burden of adjustment.

7.1 Domestic industrial gas demand suppression in the allocation of the burden of adjustment

The allocation of the share each adjustment path will play is critical in driving the overall net benefits or costs. The reason for this, as Chapter 6 indicated, is that there is a wide range in the net costs of adjustment per channel with the highest being for gas dependent industries and the lowest for the full electricity substitution case.

One approach would simply be to assume the lowest cost outcome. The full electricity substitution case may be appropriate for an efficiently planned state like China which would incorporate the strategy into its five year planning guidelines and more often than not achieve the desired result. In Australia, the mechanism for adjustment is via price changes which, in this case, will have a negative impact on economic activity and real incomes, and increase inflationary pressures via loss of competitiveness.

The fact of the matter is that adopting the full electricity substitution strategy would require a large scale investment in the electricity sector where prices would need to rise to finance it. Given the current reaction to price movements driven by large investments in electricity distribution it would appear that further rises to substitute electricity for gas would be very difficult to achieve.

The second-best course of action, the suppression of gas usage in electricity production, would also be difficult to achieve as it would require increases in the share of renewable production. As the reliance on renewables increases, the stability of the electricity system will decline in that variations in climatic conditions (perhaps aggravated by climate change) will result in greater volatility in supply. The need to have gas fired generating capacity as a back-up supply source can only increase. The reality is that by the 2020s and certainly by the 2030s, there may well be severe constraints on the ability to suppress gas usage in electricity production.

While the costs of a choice to suppress supply to gas-dependent industries are extremely high, this scenario should not be ignored without study. The reality is that it is already happening. Major domestic natural gas users in Queensland (Rio Tinto and Incitec Pivot) are already forecasting natural gas shortages by 2015. This must affect their incentive to expand in Australia and even to maintain their Australian assets at a level that would prevent medium-term closure.

The only way to ensure that gas-dependent industries do not atrophy is to ensure that they have new and guaranteed supply sources for the next three to four decades at prices that can be projected with a degree of confidence. To guarantee supplies to gas-dependent industry will require substantial interventions in the existing regime. However, the need for intervention should be put in perspective: the gas-dependent industries' entire consumption (4 million tonnes a year) is less than the allocation of gas required to keep one LNG train supplied.

Because of the uncertainty surrounding the adjustment paths, a probability approach is adopted. Table 7.1 gives the Trigen probability distribution parameter settings. The burden of the adjustment of the gas-dependent industries is biased downwards compared to their share of overall gas demand. However, the setting of the upper bound probability at 0.85 allows for cases where the burden of adjustment may well be greater.

The resulting distribution of the adjustment share of gas-dependent industries is given in Table 7.2. The mean is a 10 per cent adjustment burden with the 25th percentile at 8 per cent and the 75th percentile at 12 per cent.

For the other channels of adjustment the means are:

- suppression of gas usage in electricity production – 22 per cent; and
- a general fall in economic activity – 16 per cent.

The remaining share would be borne by the residential sector and, at the mean, would be 100 less 22 less 16 less 10, or 52 per cent. This allocation imposes a conservative bias on the analysis, as the above discussion implies that the decline in economic activity should perhaps have a greater weight than it has been accorded.

Table 7.1 Trigen probability distribution parameters – domestic natural gas suppression of the adjustment burden by sector

		Maximum lower bound	Mode	Maximum upper bound	Lower bound probability	Upper bound probability
1	Gas dependent industries – share in gas suppression	0.05	0.09	0.13	0	0.85
2	Electricity gas usage – share in gas suppression	0.15	0.20	0.25	0	1.00
3	General economy – actual decline of electricity substitution – residual given the above three outcomes	0.08	0.15	0.25	0	1.00
4	Carbon price 2040 ($/tonne)	60	100	200	0	0.9
5	Alternative natural gas input price into electricity production ($/GJ)	3	4	5	0	0.9

Table 7.2 Reserves and extraction probabilities		
	Carbon price (2009 $/tonne)	Share of natural gas dependent industries in total gas suppression (%)
Aggregate indicators		
Minimum	15.18	5.35
Maximum	219.78	16.35
Mean	119.98	10.22
Std Deviation	44.41	2.42
Distribution		
5% Percentile	45.67	6.54
10% Percentile	59.50	7.13
15% Percentile	71.17	7.65
20% Percentile	79.88	8.05
25% Percentile	88.31	8.42
30% Percentile	95.00	8.74
35% Percentile	102.51	9.03
40% Percentile	108.53	9.33
45% Percentile	114.59	9.65
50% Percentile	119.88	9.96
55% Percentile	125.38	10.33
60% Percentile	131.42	10.65
65% Percentile	137.94	11.08
70% Percentile	144.24	11.48
75% Percentile	151.91	11.93
80% Percentile	159.74	12.39
85% Percentile	168.84	12.99
90% Percentile	179.75	13.66
95% Percentile	194.48	14.57

7.2 The distribution of CO_2 price outcomes

A probability approach was taken for the determination of the CO_2 price with the probability distribution parameters given in Table 7.1. The resulting distribution for the CO_2 price is also given in Table 7.1. The mean over the project period is $120 and the 25 to 75 per cent probability benchmarks are $88 to $152 a tonne.

The operating cost of natural gas for electricity in the absence of East Coast LNG also is determined by a probability distribution with the parameters given in Table 7.1.

7.3 The impact of East Coast LNG exports on the national economy: The expected outcome

Expected outcomes from the mean settings of the various inputs are determined by the probability distributions. This applies whether the input variable is carbon prices or estimates of natural gas reserves to be discovered. The expected results are given in Tables A.11 to A.13.

From Table A.8 there is some risk of gas shortages by 2020, though the risk is not large. What is significant is the inability to secure long-term contracts for gas at competitive rates as gas producers see the opportunity of LNG exports as a windfall, particularly since some LNG plants have yet to secure all their needs. This is the real driver of the crowding out of domestic supply which will have a very significant negative impact on downstream production, jobs and overall economic benefit.

The GDP increase at market prices is initially greater than the direct impact of the LNG exports. Employment increases by 82,000 compared to what would have otherwise been the case. From Table A.8, however, over the 2020s, the expectation is that domestic gas demand will be suppressed by 592 PJ on an average annual basis. This means that by 2020 the positive stimulus from the LNG exports is fully offset by the negative stimulus of the crowding out by gas suppression. All the production series are negative with the greatest decline being for NNP.

The decline continues but at a slower rate in the outcomes for the 2020-2025 period. By 2040 the decline is $22 billion for gross domestic product at market prices, while the net national product is $34 billion lower in 2040 compared to what otherwise would have been the case. The decline by 2040 is 775,000 in employment, while the benefit indicator declines by $46 billion, compared to the disallowance of East Coast LNG exports. This represents about 1.6 to 1.8 per cent below what national baseline GDP would be expected to be by 2040.

The employment loss may appear implausibly large. However, it is likely that the main response to a decline in employment will be via reduction in immigration. The employment loss over 30 years implies a net average annual reduction in immigration of some 35,000. The response to this may be that there is no national loss if the cost is borne by residents who will not be in Australia. The risk is, however, that the decline in employment may be so great that the required level of immigration will fall below the “bedrock” 170,000 to 200,000 level. In this case there will be increases in the effective unemployment rate. There is a limit to the size of a negative shock which can be imposed on the economy without considerable eventual economic pain.

The cumulative decline of the net benefit indicator is $160 billion. If the probability distribution for the expected reserves is near reality, the only strategy to minimise costs is to reduce LNG exports by the amount of the expected supply shortage. By 2040 the expected supply shortage equals the LNG requirement. This is, of course, when the plants are near the end of their expected life. The critical time is in the mid-2020s when the supply shortage is half the LNG demand.

In this context a prudent strategy would have been to perhaps approve one project and delay the approval of other projects until:

(i) the local industry was protected by identified reserves which are allocated to domestic use with a minimum headline reserve to production rate of 20 to 1 by 2040 given expected demand growth; and

(ii) identified available reserves support any new projects over there complete life.

7.4 The range of possible outcomes

Table A.10 shows the distribution of expected outcomes around the mean outcomes for 2020 and 2040. High negative outcomes would result if the ACIL Tasman estimates of remaining natural gas reserves are anywhere near the mark. The low negative and marginally positive outcomes would occur if the alternative estimates of reserves by COE are near the mark, at least in terms of reserves that can be extracted at $10/GJ.

The point about the results is that even if the reserves remaining are at the upper end of the range, the benefit of the East Coast LNG projects are marginal in that costs and benefits are in balance. This is clearly shown in Table A.10 where, if eventually recoverable reserves are near 240,000 PJ, the value of the net benefit indicator in 2040 is $2.4 billion.

7.5 Conclusion

The most important point of all is that even if ultimately recoverable reserves are in fact near the upper range currently assessed, or indeed in excess of the upper range, if these reserves are not identified and they cannot be quickly extracted to meet shortfalls at reasonable costs, the negative consequences in the table are likely to be realised. This is because:

(i) the natural gas dependent industries will not expand and would most likely go into decline;

(ii) gas using electricity plants will not be built; and

(iii) unnecessary costs will be imposed on the economy because businesses and Governments in the main will base demand on realised outcomes with an allowance for future supply security.

To illustrate the issue, assume that the ultimate recoverable reserves are 300,000 PJ. If gas producers continue their practice of allocating resources to export the reserves will not be identified and extracted for domestic use unless Governments force them to do so. The negative results of this analysis would remain, albeit reduced by the additional benefits of another LNG train or two. The only certain way to prevent the negative outcomes of this chapter is the identification and allocation of sufficient reserves for domestic use to cater for their needs for the next 30 to 40 years. In this context the estimates of overall remaining reserves are irrelevant. In any case, given the conservative allocation of weights in this study (that is, biased to low cost options), the benefits of additional potential reserves are likely to be neutralised by increasing the weight towards the higher cost adjustment options.

A related issue is the ownership structure of the enterprises which control the identification of reserves. If their interests are in "just-in-time" identification of reserves, a significant proportion of the negative consequences identified above will still be realised, even if the actual level of eventually recoverable reserves is much greater. Unfortunately, on the estimates presented here, future reserve estimates will affect domestic investment decisions even if they turn out to be too low.

Under the current reserves management practice and with the pipeline infrastructure limitations, Australia does not seem to have enough available reserves of gas to be able to avoid the negative effects of large increases in demand or of falls in the headline reserve/production ratio on business decision making.

8. East Coast LNG expansion: Additional downside risks

Three additional areas could add to the net cost over and above those identified in the previous chapters. These include:

(i) lower prices for LNG than expected;

(ii) higher alternative benefits from the use of the gas domestically; and

(iii) balance of payments adjustment costs to a rapid decline in the terms of trade.

8.1 East Coast LNG expansion: The impact of lower LNG prices

On the world stage, identified recoverable shale gas reserves, together with the extraction of the resource, are now growing strongly, particularly in the United States. United States reserves are large, estimated currently at 865 Tcf with relative low cost investment and production costs at around $4 to $6 per GJ. As a result, shale gas currently constitutes one quarter of United States total gas production and this is expected to increase to 50 per cent by 2035.

Once the United States authorities are satisfied that there is sufficient gas to satisfy domestic requirements for the foreseeable future, large scale LNG exports may be encouraged. Initially this will be done at low cost, converting LNG import infrastructure (currently unused because of the rapid expansion of shale gas production) to LNG export plants.

Given the analysis of the previous section, where the extraction costs are expected to rise to the $7 to $10 per GJ range because of resource depletion, the export of lower cost gas from the United States could force a $2 to $4 reduction in the export LNG price from the East Coast which would be a reduction of between 14 and 28 per cent. Even if LNG prices for East Coast Australia are linked, in part, to the price of oil, downward price pressure will not be avoided. The United States will not allow large scale export of gas until the gas has been fully utilised domestically to maximise the reduction in its dependence on oil imports. Other countries with substantial shale gas resources will also apply the same policies which, combined, will put significant downward pressure on oil prices and hence LNG prices.

If it is assumed that world-wide expansion of shale gas extraction reduces LNG prices by, in real terms, 20 per cent by the latter part of this decade, the effect of the decrease per PJ of output is:

- contribution to gross domestic product reduced by 25 per cent;
- tax receipts down by 66 per cent;
- domestic distributed income reduced by 28 per cent; and
- net national product reduced by 34 per cent.

These are average declines over the first 20 years of the project. The decline in tax revenue occurs because the collection of PRRT revenue is delayed until towards the end of the life of the project.

Table 8.1 shows the economy-wide impact given the above assumed price changes. The base case price is the 2011 level. The alternative case is a 20 per cent reduction in this level.

From the table, the reduction in net benefits is proportional to the reduction in the input parameters. The reduction in the net benefit indicator is $171 million for 50 PJ of exports, or a 43 per cent reduction to $229 million from the base case of $401 million.

This result provides the rule of thumb that:

- **for every 1 per cent reduction in the LNG price the economy-wide benefits from LNG exports will be reduced by approximately 2 percentage points. This stems mainly from the fact that tax receipts and domestic profits will be disproportionately impacted. Interest owed overseas will still have to be paid and debt repaid.**

Table 8.1 The impact of lower LNG prices

		Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Macroeconomic aggregates				
Gross domestic product at factor cost	$2009m	729.56	-186.22	543.34
Gross domestic product at market prices	$2009m	767.76	-198.23	569.53
Gross national product at market prices	$2009m	538.64	-187.21	351.43
Net national product at market prices	$2009m	355.40	-132.73	222.67
Total imports of goods and services	$2009m	75.85	-21.53	54.33
Total employment	**ths.**	**4.28**	**-1.25**	**3.03**
Household activity				
Wages and mixed income	$2009m	170.21	-48.13	122.08
Property income	$2009m	128.49	-54.30	74.20
Direct taxes paid	$2009m	67.21	-23.05	44.16
Household consumption	$2009m	184.68	-63.33	121.36
Government revenue				
Direct taxes on households	$2009m	67.21	-23.05	44.16
Direct taxes on business	$2009m	156.55	-112.19	44.36
Indirect taxes	$2009m	38.21	-12.01	26.19
Total tax revenue	$2009m	261.96	-147.24	114.72
Other indicators				
Income paid overseas	$2009m	229.12	-11.03	218.10
Benefit indicator	$2009m	401.02	-171.65	229.37

8.2 Foregone growth benefits from expansion of the chemicals sector

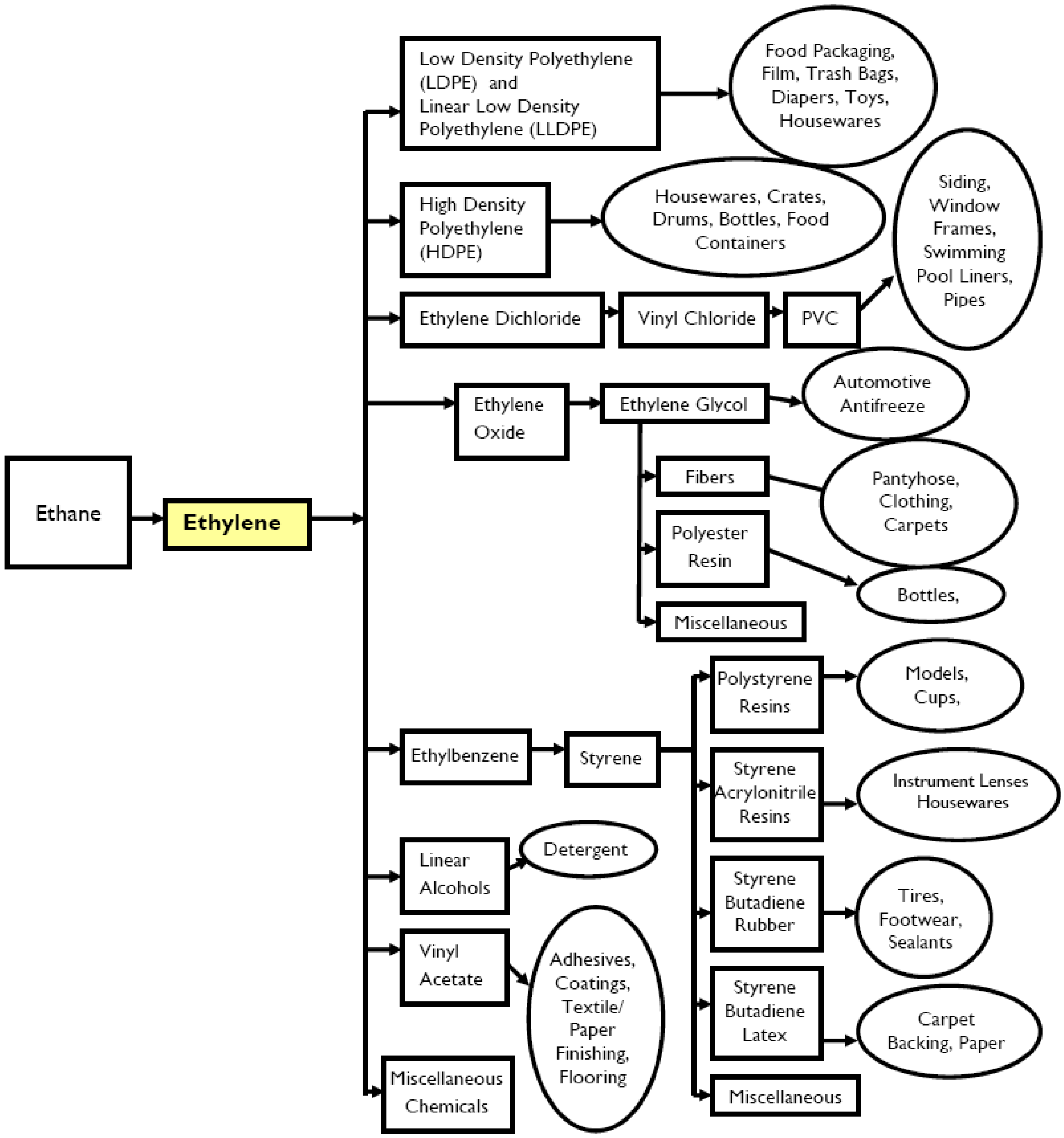
The analysis of Chapters 4 to 7 above were in the context of the existing chemicals sector being crowded out by natural gas shortages. This analysis provided minimum estimates which made no allowance for the foregone ability to grow the chemicals sector as a strategic industry – not only the gas-intensive chemicals industry (fertilizers, explosives) but also that part of the chemicals industry which uses natural gas liquids in general, and ethane in particular. Ethane is the next largest component of natural gas after methane. Its concentration varies from negligible levels to up to 6 per cent of a natural gas deposit. As Figure 8.1 shows, ethane is used to produce ethylene, which is an essential input into a wide range of chemical products.

A 2011 study by the American Chemistry Council (ACC) examined the benefits to the United States of an expansion in the chemicals industry enabled by expanded supply of natural gas. The American study had an indirect (that is inter-industry) effect of $US36 billion from a hypothetical but plausible 25 per cent increase in ethane supply. The ACC study used a completely unconstrained input output framework whereas for this study the chemical sector is treated as a constrained set of industries because of the methodology assuming it is constrained by gas supply. Therefore for this study it was necessary to estimate the indirect inter-industry effect on the rest of the chemical sector by the methodology outlined in developing the data in Table 4.2 which underlies the multiplier of 1.6 for the chemical sector as a whole. The induced multiplier for this study in the context of the Australian economy is of the order of 1.4. This represents the employment income, household consumption expenditure induced plus the non-chemical inter-industry effects which are identical to the Chemical Council study in methodology and concept. Thus if the Australian basic chemical value of $168 million per PJ is multiplied by 1.60 and 1.4 the result is $376 million per PJ which is less than the $415 million per PJ for the American study. The American total multiplier would be expected to be bigger because of the lower import content of the American economy and the greater complexity of the inter-industry supply chains.

Once this adjustment is taken into account the two studies are extremely similar in their quantitative conclusions.

If the investment effects are taken into account an interesting conclusion emerges. While the investment to output ratio for LNG is between 4.0 and 4.5 times the annual value of output, the equivalent ratio for the chemical sector is 0.5 because of the greater value extracted from the chemical sector use of natural gas. The value of output per PJ of natural gas used by the chemicals sector is 2.7 times that for the LNG sector. There is no validity in the argument that LNG should be promoted simply because of its investment intensity.

Figure 8.1: Ethane/Ethylene and the chemical industry flow chart



Source: American Chemistry Council, "*Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs and US Manufacturing*", March 2011.

8.3 The costs of adjustment when the mining boom ends

When the mining boom ends, the terms of trade will decline, the exchange rate will fall and the current account deficit will expand rapidly to double digit levels as a percentage of GDP. The current account deficit circa 2016 to 2020 at least will be around 5 to 6 per cent of GDP with terms of trade near current levels, and given Australia's existing high net international debt any fall in the terms of trade will increase the measured debt and require that the current account deficit be closed rapidly back to the 5 per cent of GDP mark.

Normally the exchange rate decline would be expected to carry some of the burden by facilitating an export expansion/import replacement response to cushion the impact on economic activity. However Australia is destroying capacity in its non-resource trade-exposed industries from a combination of natural gas suppression and the investment-discouraging effects of the loss of competitiveness due to the high exchange rate which has accompanied the boom in mining investment. (Admittedly the iron ore export industry bears major responsibility for the high exchange rate, but LNG exports have played a role.) The high prices for iron ore, coal and other mineral exports are bound to subside, if only because of current investment in expanding capacity in Australia, Africa and elsewhere, and when the high prices fall the Australian dollar exchange rate is likely to fall with them. At this point the loss of capacity in manufacturing, tourism and other trade-exposed industries will have two unpleasant consequences:

(i) the current account deficit will be considerably worse than what would have been the case; and

(ii) most of the adjustment required to bring the current account deficit back to sustainable levels will have to come from demand suppression via contractionary monetary and fiscal policies.

To illustrate, from Table A.11, the expected benefit from East Coast LNG exports would lead to a $6 billion increase in imports. At an average 20 per cent share of imports in GDP to neutralise the impact of the import increase of the balance of payments will require a loss in GDP of $30 billion. However, normal income elasticity effects will reduce this to around $15 billion. This is because imports are highly elastic with respect to GDP change. Even so, it is two to four times the expected GDP loss from Table A.11 from East Coast LNG exports in the 2020s.

Hence, the following rule of thumb.

- **For every $1m of lost GDP from the absence of effective policies to neutralise the impact of domestic gas suppression costs on the economy, at least an additional $2 million will be lost from the current damage being done to the Australian non-resource tradeable industries from the general effects of the currently high exchange rate and potentially from domestic gas suppression.**

This analysis has only been done in terms of the marginal case of Table A.11. The risks for the national economy in the period 2016-2020 appear to require careful analysis. The inference from the above calculations is that a sharp end to the mining boom and a return of the terms of trade to near pre 2005 levels would risk severe economic instability.

9. A review of current policy is urgent

It is not the task of this study to outline the appropriate policy regime. This study goes no further than demonstrating that, unless an appropriate policy regime is put in place, the cost of East Coast LNG exports from Australia is likely to be a net negative for the national economy.

In order to avoid the likelihood of net negative consequences to the economy, a policy review is urgent that considers the impacts and risks discussed in this report and develops policies which gave continuity to existing and potential large scale uses of natural gas in regard to:

(i) adequate supply availability over a 40 year horizon;

(ii) benchmarks for the determination of costs of supply; and

(iii) institutional arrangements which would ensure that domestic customers' long-term interests are protected.

In relation to (iii), the CME study, "*The Impact of Liquefied Natural Gas on Queensland Gas Markets and Gas Users*", March 2010, points to a number of factors which will contribute to negative outcomes from the East Coast LNG exports.

Firstly, as noted in Chapter 1, the interest of gas producers in LNG plants is giving foreign customers first preference in the supply of gas in part because sales on foreign markets are expected to be more profitable than sales to domestic customers. However, as the CME report notes, even if domestic gas sales had higher margins once the LNG plant came into production the domestic sales would become small compared to foreign sales. Higher margins on domestic sales will, therefore, make a small contribution to overall profits.

The drive to secure large scale supply for export markets has driven consolidation in the gas supply industry in Queensland and greatly reduced competition. Second, the control of gas producers over pipelines and, therefore, access is also contributing to a decline in competition. This discourages smaller scale producers from expanding or commencing production. The volume of gas going through pipelines to service export markets will make it easier for pipeline owners to apply for exemptions from pipeline access on the grounds of capacity constraints.

There will indeed be producers who will be willing to supply the local market. However, as the larger producers become increasingly export focussed, these producers are likely to be small scale and, therefore, inefficient and under-capitalised, which will not assist in increasing the confidence of local gas users in long-run prospects.

In this environment the required policy regime to optimise the national interest and to avoid the costs quantified in Chapter 7 is self-evident.

Appendix A: Tables related to chapters of this report

Table A.1 Natural gas dependent industries response to 50 PJ suppression of domestic natural gas demand – macroeconomic implications of different adjustment paths

		Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Macroeconomic aggregates				
Gross domestic product at factor cost	$2009m	729.56	-11004.69	-10275.13
Gross domestic product at market Prices	$2009m	767.76	-12289.23	-11521.46
Gross national product at market prices	$2009m	538.64	-10994.01	-10455.37
Net national product at market prices	$2009m	355.40	-9112.42	-8757.02
Total imports of goods and services	$2009m	75.85	5680.81	5756.67
Total employment	**ths.**	**4.28**	**-203.34**	**-199.06**
Household activity				
Wages and mixed income	$2009m	170.21	-6441.65	-6271.45
Property income	$2009m	128.49	-2169.01	-2040.51
Direct taxes paid	$2009m	67.21	-1937.40	-1870.19
Household consumption	$2009m	184.68	-5323.87	-5139.19
Government revenue				
Direct taxes on households	$2009m	67.21	-1937.40	-1870.19
Direct taxes on business	$2009m	156.55	-706.87	-550.32
Indirect taxes	$2009m	38.21	-1284.54	-1246.33
Total tax revenue	**$2009m**	**261.96**	**-3928.81**	**-3666.85**
Other indicators				
Income paid overseas	$2009m	229.12	-1295.22	-1066.09
Benefit indicator	$2009m	401.02	-9182.55	-8781.53
Cumulative discounted (at 5%) benefit indicator 2016-2040	$2009m	4629.63	-104509.34	-99879.72

Table A.2 Gross output formation by industry ($2009m)			
	Case study: 50 PJ of natural gas allocated to LNG exports	**Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries**	**Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export**
Constrained industries			
Basic chemicals	0.00	-4202.24	-4202.24
Paints	0.00	-98.17	-98.17
Medicinal and pharmaceutical products, pesticides	0.00	-98.77	-98.77
Soap and detergents	0.00	-159.09	-159.09
Cosmetics and toiletry preparations	0.00	-55.37	-55.37
Other chemical products	0.00	-288.82	-288.82
Rubber products	0.00	-40.00	-40.00
Plastic products	0.00	-1847.01	-1847.01
Basic non-ferrous metal and products	0.00	-5951.61	-5951.61
LNG	620.73	0.00	620.73
Unconstrained industries			
Sheep	0.70	-28.13	-27.43
Grains	1.06	-47.17	-46.11
Beef cattle	1.94	-87.10	-85.15
Dairy cattle	1.08	-33.71	-32.62
Pigs	0.27	-10.67	-10.40
Poultry	0.60	-22.74	-22.14
Other agriculture	3.94	-135.46	-131.52
Services to agriculture, hunting and trapping	0.92	-39.85	-38.94
Forestry and logging	0.50	-23.60	-23.11
Commercial fishing	0.63	-18.96	-18.34
Coal	1.79	-80.86	-79.07
Gas	5.80	-83.10	-77.30
Oil	1.47	-65.27	-63.81
Iron ores	0.20	-5.91	-5.71
Non-ferrous metal ores	0.31	-2448.79	-2448.48
Other mining	0.45	-69.09	-68.64
Services to mining	15.45	-281.93	-266.48
Meat and meat products	4.60	-191.72	-187.12
Dairy products	3.54	-110.34	-106.80
Fruit and vegetable products	1.12	-33.81	-32.69
Oils and fats	0.44	-19.27	-18.83
Flour mill products and cereal foods	1.83	-72.38	-70.55
Bakery products	1.51	-45.15	-43.64
Confectionery	1.15	-35.13	-33.98
Other food products	2.69	-100.96	-98.27

Table A.2 Gross output formation by industry ($2009m) – continued			
	Case study: 50 PJ of natural gas allocated to LNG exports	**Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries**	**Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export**
Soft drinks, cordials and syrups	1.48	-46.55	-45.07
Beer and malt	1.26	-37.46	-36.20
Wine, spirits and tobacco products (a)	1.44	-45.56	-44.12
Textile fibres, yarns and woven fabrics	0.12	-6.26	-6.14
Textile products	0.37	-11.76	-11.38
Knitting mill products	0.26	-8.45	-8.19
Clothing	0.57	-18.84	-18.27
Footwear	0.12	-3.97	-3.85
Leather and leather products	0.09	-3.46	-3.36
Sawmill products	0.54	-16.20	-15.65
Other wood products	1.09	-38.72	-37.63
Pulp, paper and paperboard	0.30	-13.32	-13.01
Paper containers and products	0.90	-47.09	-46.20
Printing and services to printing	2.88	-101.92	-99.04
Publishing, recorded media, etc.	3.29	-122.30	-119.01
Petroleum and coal products	6.35	-282.82	-276.47
Glass and glass products	0.67	-27.41	-26.74
Ceramic products	0.12	-4.41	-4.30
Cement, lime and concrete slurry	0.83	-29.53	-28.70
Plaster and other concrete products	0.43	-15.83	-15.40
Other non-metallic mineral products	0.23	-7.38	-7.16
Iron and steel	4.24	-122.60	-118.36
Structural metal products	2.92	-73.11	-70.19
Sheet metal products	0.91	-37.26	-36.35
Fabricated metal products	2.23	-73.55	-71.32
Motor vehicles and parts, other transport equipment	4.75	-137.15	-132.41
Ships and boats	0.40	-13.72	-13.31
Railway equipment	1.21	-13.28	-12.06
Aircraft	1.39	-21.41	-20.02
Photographic and scientific equipment	0.91	-27.53	-26.62
Electronic equipment	0.83	-24.03	-23.20
Household appliances	1.37	-38.35	-36.98
Other electrical equipment	1.34	-41.45	-40.12
Agricultural, mining, etc. machinery	1.79	-36.27	-34.49
Other machinery and equipment	1.60	-44.46	-42.87
Prefabricated buildings	0.85	-8.07	-7.22
Furniture	1.26	-36.77	-35.51
Other manufacturing	1.07	-57.35	-56.28

Table A.2 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Electricity supply	10.97	-460.21	-449.24
Gas supply	1.10	-65.39	-64.29
Water supply, sewerage and drainage services	4.06	-157.67	-153.62
Residential building	1.94	-47.42	-45.48
Other construction	3.52	-78.84	-75.32
Construction trade services	19.47	-418.47	-399.00
Wholesale trade	25.88	-1231.10	-1205.22
Wholesale mechanical repairs	2.89	-22.17	-19.28
Other wholesale repairs	5.51	-111.48	-105.97
Retail trade	32.74	-984.54	-951.80
Retail mechanical repairs	7.63	-229.35	-221.72
Other retail repairs	0.44	-13.03	-12.59
Accommodation, cafes and restaurants	16.97	-515.86	-498.90
Road transport	9.58	-489.81	-480.23
Rail, pipeline and other transport	10.02	-111.10	-101.09
Water transport	1.13	-54.45	-53.32
Air and space transport	4.99	-155.51	-150.52
Services to transport, storage	13.62	-496.68	-483.06
Communication services	15.22	-500.67	-485.44
Finance	47.38	-1319.57	-1272.19
Ownership of dwellings	4.72	-135.99	-131.27
Other property services	31.27	-739.24	-707.97
Scientific research, technical and computer services	11.85	-445.16	-433.31
Legal, accounting, marketing and business management services	18.85	-766.52	-747.67
Other business services	11.10	-478.61	-467.51
Government administration	2.21	-99.62	-97.42
Defence	0.03	-1.39	-1.36
Education	9.51	-282.15	-272.63
Health services	9.29	-271.61	-262.32
Community services	1.16	-33.37	-32.21
Motion picture, radio and television services	4.08	-139.92	-135.84
Libraries, museums and the arts	1.11	-36.41	-35.30
Sport, gambling and recreational services	7.78	-192.15	-184.37
Personal services	3.71	-108.00	-104.28
Other services	3.99	-119.36	-115.37
Total	**1082.81**	**-29840.57**	**-28757.76**

Table A.3 Total employment formation (ths)

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Constrained industries			
Basic chemicals	0.00	-11.20	-11.20
Paints	0.00	-1.00	-1.00
Medicinal and pharmaceutical products, pesticides	0.00	-0.80	-0.80
Soap and detergents	0.00	-0.92	-0.92
Cosmetics and toiletry preparations	0.00	-0.37	-0.37
Other chemical products	0.00	-2.81	-2.81
Rubber products	0.00	-0.35	-0.35
Plastic products	0.00	-16.88	-16.88
Basic non-ferrous metal and products	0.00	-32.47	-32.47
LNG	0.12	0.00	0.12
Unconstrained industries			
Sheep	0.01	-0.47	-0.46
Grains	0.01	-0.41	-0.40
Beef cattle	0.03	-1.24	-1.21
Dairy cattle	0.01	-0.45	-0.43
Pigs	0.01	-0.26	-0.25
Poultry	0.01	-0.20	-0.20
Other agriculture	0.04	-1.28	-1.24
Services to agriculture, hunting and trapping	0.01	-0.29	-0.28
Forestry and logging	0.00	-0.17	-0.16
Commercial fishing	0.00	-0.12	-0.12
Coal	0.00	-0.10	-0.10
Gas	0.00	-0.07	-0.06
Oil	0.00	-0.03	-0.03
Iron ores	0.00	-0.01	-0.01
Non-ferrous metal ores	0.00	-5.15	-5.15
Other mining	0.00	-0.26	-0.25
Services to mining	0.10	-1.88	-1.78
Meat and meat products	0.07	-2.82	-2.75
Dairy products	0.04	-1.17	-1.13
Fruit and vegetable products	0.01	-0.20	-0.19
Oils and fats	0.00	-0.08	-0.08
Flour mill products and cereal foods	0.01	-0.51	-0.50
Bakery products	0.03	-0.97	-0.94
Confectionery	0.01	-0.24	-0.23
Other food products	0.02	-0.63	-0.61

Table A.3 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Soft drinks, cordials and syrups	0.01	-0.19	-0.18
Beer and malt	0.00	-0.12	-0.11
Wine, spirits and tobacco products (a)	0.01	-0.17	-0.16
Textile fibres, yarns and woven fabrics	0.00	-0.04	-0.04
Textile products	0.01	-0.16	-0.16
Knitting mill products	0.00	-0.07	-0.07
Clothing	0.01	-0.33	-0.32
Footwear	0.00	-0.04	-0.04
Leather and leather products	0.00	-0.02	-0.02
Sawmill products	0.00	-0.12	-0.12
Other wood products	0.02	-0.58	-0.56
Pulp, paper and paperboard	0.00	-0.05	-0.05
Paper containers and products	0.01	-0.35	-0.34
Printing and services to printing	0.03	-1.01	-0.98
Publishing, recorded media, etc.	0.03	-0.94	-0.92
Petroleum and coal products	0.01	-0.64	-0.63
Glass and glass products	0.01	-0.26	-0.25
Ceramic products	0.00	-0.04	-0.03
Cement, lime and concrete slurry	0.00	-0.12	-0.11
Plaster and other concrete products	0.00	-0.08	-0.08
Other non-metallic mineral products	0.00	-0.09	-0.09
Iron and steel	0.04	-1.10	-1.07
Structural metal products	0.02	-0.45	-0.43
Sheet metal products	0.00	-0.17	-0.16
Fabricated metal products	0.02	-0.78	-0.76
Motor vehicles and parts, other transport equipment	0.05	-1.53	-1.48
Ships and boats	0.00	-0.05	-0.05
Railway equipment	0.00	-0.05	-0.05
Aircraft	0.01	-0.09	-0.08
Photographic and scientific equipment	0.01	-0.29	-0.28
Electronic equipment	0.01	-0.26	-0.25
Household appliances	0.01	-0.33	-0.32
Other electrical equipment	0.01	-0.41	-0.40
Agricultural, mining, etc. machinery	0.02	-0.40	-0.38
Other machinery and equipment	0.02	-0.49	-0.47
Prefabricated buildings	0.01	-0.06	-0.05
Furniture	0.03	-0.89	-0.86
Other manufacturing	0.01	-0.71	-0.70

Table A.3 Total employment formation (ths) – continued	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Electricity supply	0.03	-1.38	-1.35
Gas supply	0.01	-0.55	-0.54
Water supply, sewerage and drainage services	0.02	-0.68	-0.67
Residential building	0.01	-0.23	-0.22
Other construction	0.02	-0.56	-0.53
Construction trade services	0.29	-6.23	-5.94
Wholesale trade	0.19	-9.03	-8.84
Wholesale mechanical repairs	0.02	-0.15	-0.13
Other wholesale repairs	0.05	-0.94	-0.90
Retail trade	0.56	-16.80	-16.24
Retail mechanical repairs	0.20	-6.06	-5.86
Other retail repairs	0.01	-0.28	-0.27
Accommodation, cafes and restaurants	0.25	-7.51	-7.26
Road transport	0.10	-4.86	-4.77
Rail, pipeline and other transport	0.08	-0.89	-0.81
Water transport	0.01	-0.28	-0.28
Air and space transport	0.04	-1.10	-1.07
Services to transport, storage	0.07	-2.57	-2.50
Communication services	0.09	-3.10	-3.01
Finance	0.19	-5.40	-5.20
Ownership of dwellings	0.00	0.00	0.00
Other property services	0.11	-2.51	-2.41
Scientific research, technical and computer services	0.13	-4.86	-4.73
Legal, accounting, marketing and business management services	0.17	-6.95	-6.78
Other business services	0.08	-3.64	-3.55
Government administration	0.03	-1.18	-1.16
Defence	0.00	-0.01	-0.01
Education	0.12	-3.66	-3.54
Health services	0.11	-3.31	-3.20
Community services	0.02	-0.50	-0.48
Motion picture, radio and television services	0.03	-1.08	-1.05
Libraries, museums and the arts	0.02	-0.77	-0.74
Sport, gambling and recreational services	0.11	-2.77	-2.66
Personal services	0.10	-2.77	-2.68
Other services	0.05	-1.43	-1.38
Total	**4.28**	**-203.34**	**-199.06**

Table A.4 General economy responses to 50 PJ suppression of domestic natural gas demand – macroeconomic implications of different adjustment paths

		Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Macroeconomic aggregates								
Gross domestic product at factor cost	$2009m	729.56	469.54	1199.10	-4658.41	-3928.85	-206.25	523.31
Gross domestic product at market Prices	$2009m	767.76	402.91	1170.67	-5697.53	-4929.77	-282.58	485.18
Gross national product at market prices	$2009m	538.64	211.60	750.23	-5492.32	-4953.68	-296.18	242.45
Net national product at market prices	$2009m	355.40	-3.10	352.30	-4966.96	-4611.56	-307.24	48.16
Total imports of goods and services	$2009m	75.85	-64.14	11.72	-1521.38	-1445.52	-113.45	-37.60
Total employment	**Ths**	**4.28**	**-0.50**	**3.78**	**-92.67**	**-88.39**	**-5.72**	**-1.44**
Household activity								
Wages and mixed income	$2009m	170.21	-1.13	169.07	-3130.00	-2959.80	-209.59	-39.39
Property income	$2009m	128.49	264.86	393.36	-922.44	-793.95	16.41	144.90
Direct taxes paid	$2009m	67.21	59.34	126.55	-911.80	-844.59	-43.47	23.74
Household consumption	$2009m	184.68	-831.59	-646.91	-6410.88	-6226.20	-576.70	-392.02

Table A.4 General economy responses to 50 PJ suppression of domestic natural gas demand – macroeconomic implications of different adjustment paths (continued)

		Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Government revenue								
Direct taxes on households	$2009m	67.21	59.34	126.55	-911.80	-844.59	-43.47	23.74
Direct taxes on business	$2009m	156.55	-4.20	152.34	-248.23	-91.68	-26.12	130.42
Indirect taxes	$2009m	38.21	-66.63	-28.43	-1039.13	-1000.92	-76.33	-38.13
Total tax revenue	**$2009m**	**261.96**	**-11.50**	**250.46**	**-2199.15**	**-1937.19**	**-145.92**	**116.04**
Other indicators								
Income paid overseas	$2009m	229.12	191.31	420.44	-205.21	23.91	13.60	242.73
Benefit indicator	$2009m	401.02	-423.10	-22.07	-6788.50	-6387.47	-514.93	-113.91
Cumulative discounted (at 5%) benefit indicator 2016-2040	$2009m	4629.63	-6154.42	-1524.79	-90767.69	-86138.06	-6995.04	-2365.42

Table A.5 Gross output formation by industry ($2009m)

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Constrained industries							
Basic chemicals	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paints	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Medicinal and pharmaceutical products, pesticides	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Soap and detergents	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cosmetics and toiletry preparations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other chemical products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rubber products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Plastic products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Basic non-ferrous metal and products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LNG	620.73	0.00	620.73	0.00	620.73	0.00	620.73
Unconstrained industries							
Sheep	0.70	-2.63	-1.93	-22.11	-21.41	-1.95	-1.25
Grains	1.06	-4.28	-3.22	-34.66	-33.60	-3.08	-2.03
Beef cattle	1.94	-7.93	-5.98	-64.11	-62.17	-5.70	-3.76
Dairy cattle	1.08	-4.48	-3.40	-36.09	-35.01	-3.21	-2.13
Pigs	0.27	-1.06	-0.79	-8.69	-8.43	-0.77	-0.50
Poultry	0.60	-2.48	-1.88	-19.94	-19.34	-1.77	-1.17
Other agriculture	3.94	-16.22	-12.27	-130.01	-126.06	-11.61	-7.66
Services to agriculture, hunting and trapping	0.92	-3.57	-2.65	-29.49	-28.58	-2.61	-1.70
Forestry and logging	0.50	-0.11	0.39	-5.70	-5.20	-0.50	0.00

Table A.5 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Commercial fishing	0.63	-2.68	-2.06	-21.17	-20.54	-1.89	-1.27
Coal	1.79	127.25	129.04	15.40	17.19	38.71	40.50
Gas	5.80	-129.56	-123.77	-201.86	-196.06	-181.74	-175.94
Oil	1.47	0.52	1.98	-32.29	-30.82	-1.75	-0.28
Iron ores	0.20	0.17	0.37	-1.74	-1.54	-0.12	0.08
Non-ferrous metal ores	0.31	0.32	0.64	-3.73	-3.42	-0.20	0.11
Other mining	0.45	1.11	1.57	-4.96	-4.51	-0.08	0.38
Services to mining	15.45	-0.63	14.82	-13.67	1.78	-9.15	6.30
Meat and meat products	4.60	-18.91	-14.32	-152.31	-147.71	-13.56	-8.96
Dairy products	3.54	-14.68	-11.13	-118.18	-114.63	-10.51	-6.96
Fruit and vegetable products	1.12	-4.74	-3.62	-37.59	-36.47	-3.36	-2.24
Oils and fats	0.44	-1.80	-1.36	-14.62	-14.18	-1.30	-0.85
Flour mill products and cereal foods	1.83	-7.51	-5.68	-60.59	-58.75	-5.39	-3.56
Bakery products	1.51	-6.14	-4.63	-49.72	-48.21	-4.42	-2.91
Confectionery	1.15	-4.77	-3.62	-38.27	-37.12	-3.41	-2.26
Other food products	2.69	-10.64	-7.95	-86.71	-84.02	-7.72	-5.03
Soft drinks, cordials and syrups	1.48	-6.47	-4.99	-50.51	-49.04	-4.53	-3.05
Beer and malt	1.26	-5.01	-3.75	-40.88	-39.62	-3.63	-2.37
Wine, spirits and tobacco products (a)	1.44	-5.69	-4.25	-45.81	-44.37	-4.11	-2.67
Textile fibres, yarns and woven fabrics	0.12	-0.31	-0.19	-3.21	-3.09	-0.27	-0.15
Textile products	0.37	-1.33	-0.96	-11.30	-10.93	-1.00	-0.63
Knitting mill products	0.26	-0.99	-0.73	-8.17	-7.91	-0.73	-0.47
Clothing	0.57	-1.75	-1.18	-16.00	-15.43	-1.40	-0.83
Footwear	0.12	-0.31	-0.19	-3.63	-3.50	-0.29	-0.17

Table A.5 Gross output formation by industry ($2009m) – continued	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Leather and leather products	0.09	-0.19	-0.09	-2.23	-2.13	-0.19	-0.09
Sawmill products	0.54	0.69	1.23	-8.10	-7.56	-0.36	0.18
Other wood products	1.09	0.98	2.07	-15.03	-13.94	-0.81	0.28
Pulp, paper and paperboard	0.30	-0.54	-0.23	-7.04	-6.73	-0.57	-0.27
Paper containers and products	0.90	-2.32	-1.42	-25.71	-24.82	-2.09	-1.19
Printing and services to printing	2.88	-4.72	-1.84	-67.72	-64.84	-5.35	-2.47
Publishing, recorded media, etc.	3.29	-10.22	-6.93	-95.69	-92.40	-8.23	-4.94
Petroleum and coal products	6.35	2.25	8.60	-139.89	-133.54	-7.58	-1.23
Glass and glass products	0.67	-1.21	-0.54	-15.11	-14.43	-1.26	-0.59
Ceramic products	0.12	0.45	0.57	-1.83	-1.71	0.01	0.13
Cement, lime and concrete slurry	0.83	5.82	6.65	-6.45	-5.62	1.11	1.94
Plaster and other concrete products	0.43	5.95	6.38	-2.71	-2.28	1.50	1.93
Other non-metallic mineral products	0.23	0.52	0.75	-1.92	-1.69	-0.03	0.20
Iron and steel	4.24	3.06	7.29	-35.80	-31.57	-2.61	1.62
Structural metal products	2.92	4.69	7.60	-17.79	-14.87	-0.77	2.15
Sheet metal products	0.91	-0.80	0.11	-15.64	-14.73	-1.28	-0.37
Fabricated metal products	2.23	2.09	4.31	-19.85	-17.62	-1.26	0.97
Motor vehicles and parts, other transport equipment	4.75	-13.68	-8.93	-127.96	-123.21	-11.19	-6.45
Ships and boats	0.40	-0.91	-0.51	-9.75	-9.34	-0.84	-0.43
Railway equipment	1.21	0.70	1.91	-6.24	-5.03	-0.67	0.55
Aircraft	1.39	-1.44	-0.04	-15.97	-14.57	-1.75	-0.36
Photographic and scientific equipment	0.91	-2.04	-1.13	-23.19	-22.28	-1.92	-1.01
Electronic equipment	0.83	-0.42	0.41	-16.44	-15.61	-1.15	-0.32

Table A.5 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Household appliances	1.37	-4.11	-2.74	-38.44	-37.07	-3.33	-1.96
Other electrical equipment	1.34	16.53	17.87	-17.25	-15.92	3.76	5.10
Agricultural, mining, etc. machinery	1.79	0.47	2.26	-10.42	-8.64	-1.19	0.59
Other machinery and equipment	1.60	0.55	2.15	-14.76	-13.16	-1.21	0.39
Prefabricated buildings	0.85	-0.05	0.80	-1.29	-0.44	-0.53	0.32
Furniture	1.26	-4.00	-2.74	-36.28	-35.03	-3.16	-1.91
Other manufacturing	1.07	-0.92	0.14	-21.80	-20.73	-1.62	-0.55
Electricity supply	10.97	1617.38	1628.35	245.05	256.02	500.12	511.09
Gas supply	1.10	22.25	23.35	-21.68	-20.58	5.50	6.60
Water supply, sewerage and drainage services	4.06	-6.94	-2.89	-106.27	-102.21	-8.00	-3.94
Residential building	1.94	9.08	11.02	-18.08	-16.15	1.11	3.05
Other construction	3.52	12.53	16.05	-30.01	-26.49	0.90	4.42
Construction trade services	19.47	134.00	153.47	-124.52	-105.05	26.28	45.75
Wholesale trade	25.88	-26.98	-1.10	-528.97	-503.09	-40.62	-14.74
Wholesale mechanical repairs	2.89	1.57	4.47	-9.40	-6.51	-1.43	1.47
Other wholesale repairs	5.51	3.25	8.76	-44.94	-39.43	-3.57	1.94
Retail trade	32.74	-133.41	-100.67	-1078.70	-1045.95	-95.95	-63.20
Retail mechanical repairs	7.63	-5.42	2.21	-149.57	-141.94	-10.97	-3.35
Other retail repairs	0.44	-1.49	-1.06	-13.13	-12.69	-1.15	-0.71
Accommodation, cafes and restaurants	16.97	-61.52	-44.56	-533.81	-516.84	-46.52	-29.55
Road transport	9.58	-16.59	-7.00	-228.91	-219.32	-18.20	-8.62
Rail, pipeline and other transport	10.02	6.02	16.03	-52.46	-42.45	-5.45	4.57
Water transport	1.13	0.88	2.01	-13.55	-12.41	-0.82	0.32

Table A.5 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Air and space transport	4.99	-13.85	-8.86	-140.33	-135.34	-11.81	-6.81
Services to transport, storage	13.62	-8.85	4.77	-172.10	-158.48	-16.09	-2.47
Communication services	15.22	-24.74	-9.52	-384.41	-369.19	-29.13	-13.90
Finance	47.38	-42.08	5.30	-1081.89	-1034.51	-75.99	-28.61
Ownership of dwellings	4.72	-21.24	-16.52	-163.75	-159.04	-14.73	-10.01
Other property services	31.27	0.18	31.44	-386.50	-355.23	-30.34	0.92
Scientific research, technical and computer services	11.85	7.43	19.28	-139.34	-127.49	-8.99	2.86
Legal, accounting, marketing and business management services	18.85	-4.21	14.63	-349.65	-330.81	-23.61	-4.76
Other business services	11.10	-1.27	9.83	-207.63	-196.53	-13.59	-2.49
Government administration	2.21	-2.87	-0.66	-41.08	-38.87	-3.50	-1.29
Defence	0.03	-0.03	0.00	-0.51	-0.48	-0.04	-0.01
Education	9.51	-30.06	-20.55	-297.24	-287.73	-24.65	-15.13
Health services	9.29	-41.36	-32.08	-320.54	-311.25	-28.80	-19.51
Community services	1.16	-5.21	-4.05	-40.18	-39.02	-3.61	-2.46
Motion picture, radio and television services	4.08	-8.30	-4.21	-101.00	-96.91	-8.25	-4.17
Libraries, museums and the arts	1.11	-1.05	0.06	-29.01	-27.90	-1.92	-0.82
Sport, gambling and recreational services	7.78	-27.59	-19.80	-216.58	-208.80	-20.18	-12.39
Personal services	3.71	-16.27	-12.56	-127.06	-123.35	-11.39	-7.68
Other services	3.99	-16.76	-12.78	-135.57	-131.58	-11.99	-8.00
Total	**1082.81**	**1156.34**	**2239.14**	**-9213.92**	**-8131.11**	**-344.93**	**737.88**

Table A.6 Total employment formation (ths)

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Constrained industries							
Basic chemicals	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paints	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Medicinal and pharmaceutical products, pesticides	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Soap and detergents	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cosmetics and toiletry preparations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other chemical products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rubber products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Plastic products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Basic non-ferrous metal and products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LNG	0.12	0.00	0.12	0.00	0.12	0.00	0.12
Unconstrained industries							
Sheep	0.01	-0.04	-0.03	-0.37	-0.36	-0.03	-0.02
Grains	0.01	-0.04	-0.03	-0.30	-0.29	-0.03	-0.02
Beef cattle	0.03	-0.11	-0.09	-0.91	-0.89	-0.08	-0.05
Dairy cattle	0.01	-0.06	-0.05	-0.48	-0.46	-0.04	-0.03
Pigs	0.01	-0.03	-0.02	-0.21	-0.20	-0.02	-0.01
Poultry	0.01	-0.02	-0.02	-0.18	-0.17	-0.02	-0.01
Other agriculture	0.04	-0.15	-0.12	-1.23	-1.19	-0.11	-0.07
Services to agriculture, hunting and trapping	0.01	-0.03	-0.02	-0.21	-0.21	-0.02	-0.01
Forestry and logging	0.00	0.00	0.00	-0.04	-0.04	0.00	0.00

Table A.6 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Commercial fishing	0.00	-0.02	-0.01	-0.14	-0.14	-0.01	-0.01
Coal	0.00	0.16	0.17	0.02	0.02	0.05	0.05
Gas	0.00	-0.11	-0.10	-0.16	-0.16	-0.15	-0.14
Oil	0.00	0.00	0.00	-0.02	-0.01	0.00	0.00
Iron ores	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-ferrous metal ores	0.00	0.00	0.00	-0.01	-0.01	0.00	0.00
Other mining	0.00	0.00	0.01	-0.02	-0.02	0.00	0.00
Services to mining	0.10	0.00	0.10	-0.09	0.01	-0.06	0.04
Meat and meat products	0.07	-0.28	-0.21	-2.24	-2.17	-0.20	-0.13
Dairy products	0.04	-0.16	-0.12	-1.25	-1.21	-0.11	-0.07
Fruit and vegetable products	0.01	-0.03	-0.02	-0.22	-0.21	-0.02	-0.01
Oils and fats	0.00	-0.01	-0.01	-0.06	-0.06	-0.01	0.00
Flour mill products and cereal foods	0.01	-0.05	-0.04	-0.43	-0.42	-0.04	-0.03
Bakery products	0.03	-0.13	-0.10	-1.07	-1.03	-0.09	-0.06
Confectionery	0.01	-0.03	-0.02	-0.26	-0.25	-0.02	-0.02
Other food products	0.02	-0.07	-0.05	-0.54	-0.53	-0.05	-0.03
Soft drinks, cordials and syrups	0.01	-0.03	-0.02	-0.20	-0.20	-0.02	-0.01
Beer and malt	0.00	-0.02	-0.01	-0.13	-0.12	-0.01	-0.01
Wine, spirits and tobacco products (a)	0.01	-0.02	-0.02	-0.17	-0.16	-0.02	-0.01
Textile fibres, yarns and woven fabrics	0.00	0.00	0.00	-0.02	-0.02	0.00	0.00
Textile products	0.01	-0.02	-0.01	-0.15	-0.15	-0.01	-0.01
Knitting mill products	0.00	-0.01	-0.01	-0.07	-0.07	-0.01	0.00
Clothing	0.01	-0.03	-0.02	-0.28	-0.27	-0.02	-0.01
Footwear	0.00	0.00	0.00	-0.04	-0.04	0.00	0.00

Table A.6 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Leather and leather products	0.00	0.00	0.00	-0.01	-0.01	0.00	0.00
Sawmill products	0.00	0.01	0.01	-0.06	-0.06	0.00	0.00
Other wood products	0.02	0.01	0.03	-0.22	-0.21	-0.01	0.00
Pulp, paper and paperboard	0.00	0.00	0.00	-0.02	-0.02	0.00	0.00
Paper containers and products	0.01	-0.02	-0.01	-0.19	-0.18	-0.02	-0.01
Printing and services to printing	0.03	-0.05	-0.02	-0.67	-0.64	-0.05	-0.02
Publishing, recorded media, etc.	0.03	-0.08	-0.05	-0.74	-0.71	-0.06	-0.04
Petroleum and coal products	0.01	0.01	0.02	-0.32	-0.30	-0.02	0.00
Glass and glass products	0.01	-0.01	-0.01	-0.14	-0.14	-0.01	-0.01
Ceramic products	0.00	0.00	0.00	-0.01	-0.01	0.00	0.00
Cement, lime and concrete slurry	0.00	0.02	0.03	-0.03	-0.02	0.00	0.01
Plaster and other concrete products	0.00	0.03	0.03	-0.01	-0.01	0.01	0.01
Other non-metallic mineral products	0.00	0.01	0.01	-0.02	-0.02	0.00	0.00
Iron and steel	0.04	0.03	0.07	-0.32	-0.28	-0.02	0.01
Structural metal products	0.02	0.03	0.05	-0.11	-0.09	0.00	0.01
Sheet metal products	0.00	0.00	0.00	-0.07	-0.07	-0.01	0.00
Fabricated metal products	0.02	0.02	0.05	-0.21	-0.19	-0.01	0.01
Motor vehicles and parts, other transport equipment	0.05	-0.15	-0.10	-1.43	-1.38	-0.12	-0.07
Ships and boats	0.00	0.00	0.00	-0.04	-0.03	0.00	0.00
Railway equipment	0.00	0.00	0.01	-0.03	-0.02	0.00	0.00
Aircraft	0.01	-0.01	0.00	-0.07	-0.06	-0.01	0.00
Photographic and scientific equipment	0.01	-0.02	-0.01	-0.25	-0.24	-0.02	-0.01
Electronic equipment	0.01	0.00	0.00	-0.18	-0.17	-0.01	0.00

Table A.6 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Household appliances	0.01	-0.04	-0.02	-0.33	-0.32	-0.03	-0.02
Other electrical equipment	0.01	0.16	0.18	-0.17	-0.16	0.04	0.05
Agricultural, mining, etc. machinery	0.02	0.01	0.02	-0.11	-0.09	-0.01	0.01
Other machinery and equipment	0.02	0.01	0.02	-0.16	-0.14	-0.01	0.00
Prefabricated buildings	0.01	0.00	0.01	-0.01	0.00	0.00	0.00
Furniture	0.03	-0.10	-0.07	-0.88	-0.85	-0.08	-0.05
Other manufacturing	0.01	-0.01	0.00	-0.27	-0.26	-0.02	-0.01
Electricity supply	0.03	4.84	4.88	0.73	0.77	1.50	1.53
Gas supply	0.01	0.19	0.20	-0.18	-0.17	0.05	0.06
Water supply, sewerage and drainage services	0.02	-0.03	-0.01	-0.46	-0.44	-0.03	-0.02
Residential building	0.01	0.04	0.05	-0.09	-0.08	0.01	0.02
Other construction	0.02	0.09	0.11	-0.21	-0.19	0.01	0.03
Construction trade services	0.29	1.99	2.28	-1.85	-1.56	0.39	0.68
Wholesale trade	0.19	-0.20	-0.01	-3.88	-3.69	-0.30	-0.11
Wholesale mechanical repairs	0.02	0.01	0.03	-0.06	-0.04	-0.01	0.01
Other wholesale repairs	0.05	0.03	0.07	-0.38	-0.33	-0.03	0.02
Retail trade	0.56	-2.28	-1.72	-18.40	-17.84	-1.64	-1.08
Retail mechanical repairs	0.20	-0.14	0.06	-3.95	-3.75	-0.29	-0.09
Other retail repairs	0.01	-0.03	-0.02	-0.28	-0.27	-0.02	-0.02
Accommodation, cafes and restaurants	0.25	-0.90	-0.65	-7.77	-7.52	-0.68	-0.43
Road transport	0.10	-0.16	-0.07	-2.27	-2.18	-0.18	-0.09
Rail, pipeline and other transport	0.08	0.05	0.13	-0.42	-0.34	-0.04	0.04
Water transport	0.01	0.00	0.01	-0.07	-0.06	0.00	0.00

Table A.6 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Air and space transport	0.04	-0.10	-0.06	-0.99	-0.96	-0.08	-0.05
Services to transport, storage	0.07	-0.05	0.02	-0.89	-0.82	-0.08	-0.01
Communication services	0.09	-0.15	-0.06	-2.38	-2.29	-0.18	-0.09
Finance	0.19	-0.17	0.02	-4.43	-4.23	-0.31	-0.12
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	0.11	0.00	0.11	-1.31	-1.21	-0.10	0.00
Scientific research, technical and computer services	0.13	0.08	0.21	-1.52	-1.39	-0.10	0.03
Legal, accounting, marketing and business management services	0.17	-0.04	0.13	-3.17	-3.00	-0.21	-0.04
Other business services	0.08	-0.01	0.07	-1.58	-1.49	-0.10	-0.02
Government administration	0.03	-0.03	-0.01	-0.49	-0.46	-0.04	-0.02
Defence	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Education	0.12	-0.39	-0.27	-3.86	-3.73	-0.32	-0.20
Health services	0.11	-0.50	-0.39	-3.91	-3.79	-0.35	-0.24
Community services	0.02	-0.08	-0.06	-0.60	-0.58	-0.05	-0.04
Motion picture, radio and television services	0.03	-0.06	-0.03	-0.78	-0.75	-0.06	-0.03
Libraries, museums and the arts	0.02	-0.02	0.00	-0.61	-0.59	-0.04	-0.02
Sport, gambling and recreational services	0.11	-0.40	-0.29	-3.12	-3.01	-0.29	-0.18
Personal services	0.10	-0.42	-0.32	-3.26	-3.16	-0.29	-0.20
Other services	0.05	-0.20	-0.15	-1.62	-1.57	-0.14	-0.10
Total	**4.28**	**-0.50**	**3.78**	**-92.67**	**-88.39**	**-5.72**	**-1.44**

Table A.7 Eastern Australian estimates of suppressed gas demand – No East Coast LNG

	Cumulative suppressed gas demand 2011-2040 – petajoules (PJ)	Average annual suppressed gas demand 2011-2020 – petajoules (PJ)	Average annual suppressed gas demand 2021-2030 – petajoules (PJ)	Average annual suppressed gas demand 2031-2040 – petajoules (PJ)	Average annual ex-plant gas cost $2011 per gigajoule 2011-2020 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2021-2030 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2031-2040 – petajoules ($/GJ)	Suppressed demand as per cent of base case domestic Eastern Australian demand (%)
Aggregate indicators								
Minimum	0	0.0	0.0	0.0	5.4	6.4	7.7	0.0
Maximum	16894	0.0	522.3	1167.1	6.0	8.4	11.4	51.6
Mean	1193	0.0	11.6	107.7	5.6	7.0	9.1	9.5
Std Deviation	2269	0.0	49.1	184.0	0.1	0.4	0.8	9.3
Distribution								
5% Percentile	0	0.0	0.0	0.0	5.4	6.5	8.0	0.0
10% Percentile	0	0.0	0.0	0.0	5.4	6.6	8.1	0.0
15% Percentile	0	0.0	0.0	0.0	5.5	6.6	8.2	0.0
20% Percentile	0	0.0	0.0	0.0	5.5	6.7	8.4	0.0
25% Percentile	0	0.0	0.0	0.0	5.5	6.7	8.4	0.0
30% Percentile	86	0.0	0.0	8.6	5.5	6.8	8.5	3.2
35% Percentile	86	0.0	0.0	8.6	5.5	6.8	8.6	3.2
40% Percentile	254	0.0	0.0	25.4	5.5	6.9	8.7	6.3
45% Percentile	254	0.0	0.0	25.4	5.5	6.9	8.8	6.3
50% Percentile	259	0.0	0.0	25.9	5.6	6.9	8.9	6.3
55% Percentile	499	0.0	0.0	49.9	5.6	7.1	9.1	9.3
60% Percentile	499	0.0	0.0	49.9	5.6	7.1	9.2	9.3
65% Percentile	817	0.0	0.0	81.7	5.6	7.2	9.4	12.2
70% Percentile	817	0.0	0.0	81.7	5.7	7.3	9.5	12.2
75% Percentile	1206	0.0	0.0	120.6	5.7	7.3	9.6	15.0
80% Percentile	1432	0.0	0.0	143.2	5.7	7.4	9.8	15.0
85% Percentile	1661	0.0	0.0	166.1	5.7	7.5	9.9	17.7
90% Percentile	3067	0.0	0.0	304.2	5.8	7.7	10.3	21.2
95% Percentile	6403	0.0	77.6	578.6	5.8	7.8	10.5	28.4

Table A.8	Eastern Australian estimates of suppressed gas demand – East Coast LNG							
	Cumulative suppressed gas demand 2011-2040 – petajoules (PJ)	Average annual suppressed gas demand 2011-2020 – petajoules (PJ)	Average annual suppressed gas demand 2021-2030 – petajoules (PJ)	Average annual suppressed gas demand 2031-2040 – petajoules (PJ)	Average annual ex-plant gas cost $2011 per gigajoule 2011-2020 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2021-2030 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2031-2040 – petajoules ($/GJ)	Suppressed demand as per cent of base case domestic Eastern Australian demand (%)
Aggregate indicators								
Minimum	68.9	0.0	0.0	6.9	5.4	6.9	8.9	2.6
Maximum	43585.1	319.9	1752.8	2317.8	6.2	9.2	12.2	94.3
Mean	15170.8	40.2	597.5	883.4	5.7	7.7	10.1	40.8
Std Deviation	10525.2	59.9	450.0	562.1	0.1	0.4	0.6	19.5
Distribution								
5% Percentile	929.1	0.0	0.0	64.1	5.5	7.0	9.2	11.9
10% Percentile	1556.5	0.0	0.0	155.6	5.5	7.2	9.4	15.7
15% Percentile	2148.3	0.0	0.0	187.4	5.5	7.2	9.5	19.3
20% Percentile	2824.3	0.0	52.4	255.5	5.5	7.3	9.6	22.8
25% Percentile	5071.4	0.0	165.3	345.5	5.6	7.4	9.7	24.3
30% Percentile	7641.6	0.0	252.8	494.9	5.6	7.5	9.8	27.0
35% Percentile	9767.5	0.0	361.8	612.4	5.6	7.5	9.9	31.0
40% Percentile	11838.2	0.0	455.0	727.0	5.6	7.6	10.0	33.8
45% Percentile	13520.0	0.0	529.8	811.2	5.6	7.6	10.1	37.2
50% Percentile	15089.4	0.0	609.6	885.4	5.6	7.7	10.1	39.7
55% Percentile	16447.8	8.9	669.9	979.8	5.7	7.7	10.2	42.4
60% Percentile	17998.8	24.6	744.7	1030.2	5.7	7.8	10.3	44.6
65% Percentile	19676.0	38.2	824.7	1112.7	5.7	7.8	10.4	47.6
70% Percentile	21718.6	50.2	888.4	1209.7	5.7	7.9	10.4	51.2
75% Percentile	23340.6	63.7	952.3	1324.2	5.8	8.0	10.5	55.1
80% Percentile	25130.9	82.2	1031.1	1413.9	5.8	8.0	10.6	58.5
85% Percentile	27283.7	110.0	1113.1	1540.5	5.8	8.2	10.7	63.7
90% Percentile	29833.6	136.4	1222.5	1659.1	5.9	8.3	10.9	68.3
95% Percentile	33126.2	169.5	1339.2	1826.5	6.0	8.5	11.2	75.1

Table A.9	Eastern Australian estimates of suppressed gas demand – Impact of East Coast LNG							
	Cumulative suppressed gas demand 2011-2040 – petajoules (PJ)	Average annual suppressed gas demand 2011-2020 – petajoules (PJ)	Average annual suppressed gas demand 2021-2030 – petajoules (PJ)	Average annual suppressed gas demand 2031-2040 – petajoules (PJ)	Average annual ex-plant gas cost $2011 per gigajoule 2011-2020 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2021-2030 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2031-2040 – petajoules ($/GJ)	Suppressed demand as per cent of base case domestic Eastern Australian demand (%)
Aggregate indicators								
Minimum	68.9	0.0	0.0	6.9	0.0	0.5	1.1	2.6
Maximum	26691.3	319.9	1230.5	1150.7	0.2	0.8	0.8	42.7
Mean	13977.5	40.2	585.9	775.7	0.1	0.7	1.1	31.3
Std Deviation	8255.9	59.9	400.9	378.1	0.0	0.0	-0.2	10.2
Distribution								
5% Percentile	929.1	0.0	0.0	64.1	0.0	0.5	1.2	11.9
10% Percentile	1556.5	0.0	0.0	155.6	0.1	0.6	1.3	15.7
15% Percentile	2148.3	0.0	0.0	187.4	0.1	0.6	1.3	19.3
20% Percentile	2824.3	0.0	52.4	255.5	0.1	0.6	1.3	22.8
25% Percentile	5071.4	0.0	165.3	345.5	0.1	0.7	1.3	24.3
30% Percentile	7555.6	0.0	252.8	486.3	0.1	0.7	1.3	23.8
35% Percentile	9681.5	0.0	361.8	603.8	0.1	0.7	1.3	27.8
40% Percentile	11584.7	0.0	455.0	701.7	0.1	0.7	1.3	27.4
45% Percentile	13266.5	0.0	529.8	785.8	0.1	0.7	1.3	30.9
50% Percentile	14830.2	0.0	609.6	859.5	0.1	0.7	1.2	33.4
55% Percentile	15949.2	8.9	669.9	930.0	0.1	0.7	1.1	33.0
60% Percentile	17500.2	24.6	744.7	980.4	0.1	0.7	1.1	35.3
65% Percentile	18858.7	38.2	824.7	1031.0	0.1	0.6	1.0	35.4
70% Percentile	20901.2	50.2	888.4	1128.0	0.1	0.6	0.9	39.0
75% Percentile	22134.6	63.7	952.3	1203.6	0.1	0.6	0.9	40.1
80% Percentile	23698.6	82.2	1031.1	1270.6	0.1	0.6	0.8	43.5
85% Percentile	25622.9	110.0	1113.1	1374.5	0.1	0.7	0.8	46.0
90% Percentile	26767.1	136.4	1222.5	1354.9	0.1	0.6	0.6	47.1
95% Percentile	26723.0	169.5	1261.6	1247.8	0.1	0.7	0.7	46.7

Table A.10 Eastern Australian estimates of suppressed gas demand – No East Coast LNG

	Gross domestic product at market prices (2009 $m) – 2020	Gross domestic product at market prices (2009 $m) – 2040	Total employment (ths) – 2020	Total employment (ths) – 2020	Benefit indicator (2009 $m) – 2020	Benefit indicator (2009 $m) – 2040	Cumulative discounted net benefit indicator (5% rate) (2009 $m) 2012 – 2040	Ultimately recoverable reserves (2009 $m)	Estimates of eventually recoverable reserves as at 2012 (PJ)
Aggregate indicators									
Minimum	-26636	-109626	-672	-2161	-40493	-127105	-797201	94208	91288.9
Maximum	15118	18445	82	103	7744	9647	101184	265838	263437.8
Mean	8339	-33424	-47	-837	-319	-49917	-196062	173479	173481.8
Std Deviation	9292	28332	174	505	10880	31851	212661	36543	36426.9
Distribution									
5% Percentile	-10823	-79109	-391	-1647	-21041	-98005	-561368	115734	115200.3
10% Percentile	-3839	-69326	-279	-1477	-16162	-89901	-492412	125386	125942.1
15% Percentile	-1816	-65155	-243	-1409	-12573	-84793	-433361	133987	134066.2
20% Percentile	-75	-56463	-213	-1263	-10853	-78436	-382385	140845	140810.0
25% Percentile	1720	-52830	-179	-1208	-8621	-73908	-342773	147117	146886.9
30% Percentile	3493	-49945	-131	-1131	-5658	-69629	-313076	151931	152278.0
35% Percentile	5639	-44308	-94	-1038	-3384	-66274	-292924	157163	157293.8
40% Percentile	10072	-41612	-20	-1002	1577	-61076	-263167	161852	161965.7
45% Percentile	13688	-40193	54	-940	5990	-55411	-227867	166430	166397.9
50% Percentile	15118	-35602	82	-869	7744	-52388	-197998	170863	171161.4
55% Percentile	15118	-32403	82	-824	7744	-47911	-168263	176278	176066.5
60% Percentile	15118	-28204	82	-758	7744	-44830	-130813	181130	181323.1
65% Percentile	15118	-21513	82	-637	7744	-37388	-92761	186871	186829.0
70% Percentile	15118	-15515	82	-518	7744	-30791	-39563	192865	192840.7
75% Percentile	15118	-10561	82	-428	7744	-23149	-14712	199282	199367.6
80% Percentile	15118	-5415	82	-331	7744	-18460	25583	206500	206442.7
85% Percentile	15118	593	82	-221	7744	-10114	85246	214882	214675.4
90% Percentile	15118	6777	82	-108	7744	-3718	94371	223848	224387.3
95% Percentile	15118	12600	82	-13	7744	2518	98438	237320	236890.6

Table A.11	Queensland natural gas expansion – the expected net benefit on the national economy (with year benchmarks)						
		2015	2020	2025	2030	2035	2040
Macroeconomic aggregates							
Gross domestic product at factor cost	$2009m	0.0	14395.9	-3791.9	-6697.9	-8918.8	-22009.2
Gross domestic product at market prices	$2009m	0.0	15117.7	-7326.3	-10834.4	-13496.1	-29253.7
Gross national product at market prices	$2009m	0.0	10544.6	-12045.5	-15406.3	-17962.4	-33181.2
Net national product at market prices	$2009m	0.0	6903.3	-14433.9	-17458.7	-19785.0	-33728.5
Total imports of goods and services	$2009m	0.0	1455.2	6083.9	5781.5	6262.0	9284.3
Total employment	**ths.**	**0.0**	**81.8**	**-375.2**	**-434.3**	**-482.8**	**-774.6**
Household activity							
Wages and mixed income	$2009m	0.0	3275.8	-11437.0	-13396.2	-14975.8	-24450.8
Property income	$2009m	0.0	2528.8	352.4	-179.0	-480.5	-2156.4
Direct taxes paid	$2009m	0.0	1306.0	-2494.0	-3054.4	-3477.7	-5986.6
Household consumption	$2009m	0.0	3436.6	-22827.7	-26451.1	-29099.2	-45299.7
Government revenue							
Direct taxes on households	$2009m	0.0	1306.0	-2494.0	-3054.4	-3477.7	-5986.6
Direct taxes on business	$2009m	0.0	3121.2	2176.4	2004.9	1841.8	860.5
Indirect taxes	$2009m	0.0	721.8	-3534.3	-4136.5	-4577.3	-7244.5
Total tax revenue	**$2009m**	**0.0**	**5149.0**	**-3851.9**	**-5186.0**	**-6213.2**	**-12370.6**
Other indicators							
Income paid overseas	$2009m	0.0	4573.1	4719.2	4571.9	4466.3	3927.6
Benefit indicator	$2009m	0.0	7744.4	-20556.8	-24547.9	-27548.7	-45699.4
Cumulative discounted (at 5%) benefit indicator 2016-2040	$2009m	0.0	0.0	0.0	0.0	0.0	-160043.6

Table A.12 The impact of East Coast LNG exports on the national economy: Gross output formation by industry ($2009m)

	2015	2020	2025	2030	2035	2040
Constrained industries						
Basic chemicals	0.0	0.0	-5867.8	-6185.3	-6801.4	-10581.1
Paints	0.0	0.0	-137.1	-144.5	-158.9	-247.2
Medicinal and pharmaceutical products, pesticides	0.0	0.0	-137.9	-145.4	-159.9	-248.7
Soap and detergents	0.0	0.0	-222.1	-234.2	-257.5	-400.6
Cosmetics and toiletry preparations	0.0	0.0	-77.3	-81.5	-89.6	-139.4
Other chemical products	0.0	0.0	-403.3	-425.1	-467.5	-727.2
Rubber products	0.0	0.0	-55.9	-58.9	-64.7	-100.7
Plastic products	0.0	0.0	-2579.1	-2718.6	-2989.4	-4650.7
Basic non-ferrous metal and products	0.0	0.0	-8310.6	-8760.2	-9632.7	-14985.9
LNG	0.0	12414.5	14897.5	14897.5	14897.5	14897.5
Unconstrained industries						
Sheep	0.0	13.0	-89.1	-102.3	-112.7	-176.2
Grains	0.0	19.7	-146.0	-167.0	-183.8	-286.9
Beef cattle	0.0	36.3	-270.2	-308.9	-340.1	-530.7
Dairy cattle	0.0	20.2	-131.1	-151.8	-167.1	-260.7
Pigs	0.0	5.0	-34.8	-40.0	-44.0	-68.8
Poultry	0.0	11.2	-78.2	-89.9	-98.9	-154.4
Other agriculture	0.0	73.7	-491.7	-567.1	-624.4	-974.7
Services to agriculture, hunting and trapping	0.0	17.1	-122.9	-140.7	-154.9	-242.1
Forestry and logging	0.0	9.7	-34.2	-38.7	-43.5	-72.3
Commercial fishing	0.0	11.7	-76.5	-88.5	-97.4	-151.9
Coal	0.0	34.9	1028.6	1061.6	1150.7	1749.2
Gas	0.0	115.1	-2135.4	-2272.8	-2519.9	-4005.1
Oil	0.0	28.0	-117.6	-137.5	-153.1	-246.0
Iron ores	0.0	4.0	-5.8	-7.0	-8.2	-14.9
Non-ferrous metal ores	0.0	6.1	-3417.2	-3603.8	-3963.4	-6168.9
Other mining	0.0	8.8	-87.0	-94.3	-104.6	-167.1

Table A.12 The impact of East Coast LNG exports on the national economy: Gross output formation by industry ($2009m) – continued	2015	2020	2025	2030	2035	2040
Services to mining	0.0	308.8	-97.0	-125.1	-175.6	-479.9
Meat and meat products	0.0	85.8	-621.9	-712.7	-784.6	-1224.3
Dairy products	0.0	66.1	-429.4	-496.9	-547.1	-853.6
Fruit and vegetable products	0.0	20.9	-135.5	-156.9	-172.7	-269.4
Oils and fats	0.0	8.2	-60.8	-69.5	-76.6	-119.5
Flour mill products and cereal foods	0.0	34.2	-241.8	-277.6	-305.6	-476.9
Bakery products	0.0	28.2	-178.2	-206.5	-227.4	-355.1
Confectionery	0.0	21.5	-138.3	-160.1	-176.3	-275.1
Other food products	0.0	50.3	-340.0	-391.0	-430.7	-673.1
Soft drinks, cordials and syrups	0.0	27.6	-185.1	-214.0	-235.5	-366.9
Beer and malt	0.0	23.5	-146.3	-169.6	-186.8	-291.9
Wine, spirits and tobacco products (a)	0.0	27.0	-168.9	-195.3	-215.2	-336.7
Textile fibres, yarns and woven fabrics	0.0	2.3	-14.9	-17.0	-18.8	-29.6
Textile products	0.0	7.0	-41.4	-47.9	-52.9	-82.9
Knitting mill products	0.0	4.8	-30.3	-35.0	-38.6	-60.4
Clothing	0.0	10.7	-59.7	-69.1	-76.3	-120.3
Footwear	0.0	2.3	-12.6	-14.6	-16.2	-25.4
Leather and leather products	0.0	1.8	-8.7	-10.0	-11.1	-17.8
Sawmill products	0.0	10.6	-20.8	-25.6	-29.1	-49.8
Other wood products	0.0	21.1	-51.5	-61.3	-69.3	-117.1
Pulp, paper and paperboard	0.0	5.8	-30.2	-34.6	-38.4	-61.2
Paper containers and products	0.0	16.9	-115.6	-131.9	-145.5	-228.7
Printing and services to printing	0.0	54.8	-250.9	-291.6	-323.5	-516.7
Publishing, recorded media, etc.	0.0	62.0	-370.7	-427.5	-471.8	-741.9
Petroleum and coal products	0.0	121.2	-509.4	-596.0	-663.2	-1066.0
Glass and glass products	0.0	12.8	-63.2	-72.7	-80.6	-128.8
Ceramic products	0.0	2.2	-3.4	-4.4	-5.1	-8.9
Cement, lime and concrete slurry	0.0	16.3	13.1	9.3	8.0	3.1
Plaster and other concrete products	0.0	8.4	32.1	31.1	32.7	45.6

Table A.12 The impact of East Coast LNG exports on the national economy: Gross output formation by industry ($2009m) – continued

	2015	2020	2025	2030	2035	2040
Other non-metallic mineral products	0.0	4.4	-4.8	-6.1	-7.2	-13.7
Iron and steel	0.0	83.3	-124.1	-149.5	-173.2	-314.2
Structural metal products	0.0	57.6	-34.7	-47.5	-58.9	-125.3
Sheet metal products	0.0	17.6	-69.4	-79.8	-89.0	-145.0
Fabricated metal products	0.0	43.7	-75.9	-90.2	-103.8	-184.8
Motor vehicles and parts, other transport equipment	0.0	89.8	-451.6	-525.6	-581.1	-919.4
Ships and boats	0.0	7.7	-37.0	-42.8	-47.4	-75.6
Railway equipment	0.0	24.0	1.2	-2.6	-5.6	-23.1
Aircraft	0.0	27.3	-43.0	-52.5	-60.2	-106.6
Photographic and scientific equipment	0.0	17.3	-80.8	-94.3	-104.4	-166.0
Electronic equipment	0.0	15.9	-51.0	-60.7	-67.8	-110.6
Household appliances	0.0	25.9	-132.9	-154.9	-171.1	-270.0
Other electrical equipment	0.0	25.8	76.9	69.8	73.0	100.4
Agricultural, mining, etc. machinery	0.0	35.3	-28.7	-36.2	-43.8	-88.7
Other machinery and equipment	0.0	31.4	-51.8	-62.0	-71.3	-127.3
Prefabricated buildings	0.0	17.0	3.9	2.7	0.9	-9.9
Furniture	0.0	23.7	-128.0	-148.8	-164.3	-258.8
Other manufacturing	0.0	20.5	-107.0	-121.8	-135.3	-216.7
Electricity supply	0.0	209.5	13710.6	14196.4	15426.2	23620.7
Gas supply	0.0	20.8	78.2	68.7	72.1	103.4
Water supply, sewerage and drainage services	0.0	76.8	-396.4	-460.1	-509.2	-806.9
Residential building	0.0	37.9	16.9	7.0	3.1	-15.5
Other construction	0.0	69.1	12.9	-4.1	-12.7	-57.7
Construction trade services	0.0	382.9	721.2	664.5	677.3	822.6
Wholesale trade	0.0	496.1	-2411.8	-2760.3	-3066.7	-4922.9
Wholesale mechanical repairs	0.0	57.5	25.7	20.0	15.1	-12.7
Other wholesale repairs	0.0	108.4	-97.4	-126.2	-150.3	-292.6
Retail trade	0.0	611.5	-3874.5	-4489.3	-4943.5	-7719.1
Retail mechanical repairs	0.0	146.5	-490.9	-579.9	-647.6	-1054.8

Table A.12 The impact of East Coast LNG exports on the national economy: Gross output formation by industry ($2009m) – continued						
	2015	**2020**	**2025**	**2030**	**2035**	**2040**
Other retail repairs	0.0	8.2	-46.7	-54.2	-59.8	-94.0
Accommodation, cafes and restaurants	0.0	317.8	-1903.2	-2208.5	-2434.2	-3811.9
Road transport	0.0	182.4	-1059.5	-1208.2	-1337.7	-2124.3
Rail, pipeline and other transport	0.0	198.3	7.8	-23.9	-48.9	-194.1
Water transport	0.0	22.1	-70.6	-80.9	-91.0	-152.1
Air and space transport	0.0	94.2	-497.3	-578.4	-639.1	-1008.3
Services to transport, storage	0.0	265.5	-809.1	-929.8	-1045.8	-1747.7
Communication services	0.0	288.8	-1322.0	-1546.7	-1714.2	-2727.7
Finance	0.0	903.3	-3266.8	-3885.7	-4324.4	-6963.1
Ownership of dwellings	0.0	87.8	-583.1	-675.6	-743.3	-1157.1
Other property services	0.0	609.7	-1108.0	-1345.8	-1535.6	-2671.3
Scientific research, technical and computer services	0.0	231.3	-574.5	-671.9	-761.0	-1294.2
Legal, accounting, marketing and business management services	0.0	362.6	-1376.3	-1599.8	-1785.5	-2903.2
Other business services	0.0	213.5	-841.6	-975.7	-1088.4	-1766.6
Government administration	0.0	42.5	-195.3	-222.8	-247.9	-400.1
Defence	0.0	0.5	-2.6	-2.9	-3.2	-5.2
Education	0.0	178.2	-1015.8	-1184.4	-1306.1	-2047.0
Health services	0.0	172.9	-1146.0	-1327.5	-1460.6	-2274.4
Community services	0.0	21.5	-143.1	-165.8	-182.4	-283.9
Motion picture, radio and television services	0.0	77.6	-372.4	-432.5	-479.2	-762.5
Libraries, museums and the arts	0.0	20.9	-91.8	-108.4	-120.2	-191.1
Sport, gambling and recreational services	0.0	147.0	-751.3	-874.5	-966.0	-1525.0
Personal services	0.0	69.1	-453.0	-524.9	-577.6	-899.9
Other services	0.0	74.3	-483.5	-560.5	-616.8	-961.4
Total	**0.000**	**21268**	**-25534**	**-31834**	**-37239**	**-69242**

Table A.13 The impact of East Coast LNG exports on the national economy: Total employment formation (ths)

	2015	2020	2025	2030	2035	2040
Constrained industries						
Basic chemicals	0.000	0.000	-15.639	-16.485	-18.127	-28.201
Paints	0.000	0.000	-1.390	-1.465	-1.611	-2.506
Medicinal and pharmaceutical products, pesticides	0.000	0.000	-1.115	-1.175	-1.292	-2.010
Soap and detergents	0.000	0.000	-1.288	-1.358	-1.493	-2.322
Cosmetics and toiletry preparations	0.000	0.000	-0.523	-0.551	-0.606	-0.943
Other chemical products	0.000	0.000	-3.920	-4.133	-4.544	-7.069
Rubber products	0.000	0.000	-0.485	-0.512	-0.563	-0.875
Plastic products	0.000	0.000	-23.566	-24.841	-27.315	-42.495
Basic non-ferrous metal and products	0.000	0.000	-45.336	-47.789	-52.549	-81.751
LNG	0.000	2.359	2.831	2.831	2.831	2.831
Unconstrained industries						
Sheep	0.000	0.217	-1.483	-1.702	-1.875	-2.933
Grains	0.000	0.170	-1.260	-1.441	-1.587	-2.477
Beef cattle	0.000	0.517	-3.850	-4.401	-4.845	-7.561
Dairy cattle	0.000	0.268	-1.740	-2.014	-2.217	-3.460
Pigs	0.000	0.120	-0.834	-0.958	-1.055	-1.648
Poultry	0.000	0.101	-0.704	-0.810	-0.892	-1.391
Other agriculture	0.000	0.697	-4.652	-5.365	-5.907	-9.222
Services to agriculture, hunting and trapping	0.000	0.124	-0.891	-1.019	-1.123	-1.754
Forestry and logging	0.000	0.069	-0.244	-0.276	-0.310	-0.515
Commercial fishing	0.000	0.077	-0.503	-0.582	-0.641	-0.999
Coal	0.000	0.045	1.330	1.373	1.488	2.262
Gas	0.000	0.094	-1.743	-1.855	-2.057	-3.269
Oil	0.000	0.013	-0.055	-0.064	-0.072	-0.115
Iron ores	0.000	0.004	-0.006	-0.007	-0.008	-0.014
Non-ferrous metal ores	0.000	0.013	-7.191	-7.584	-8.340	-12.981
Other mining	0.000	0.033	-0.323	-0.350	-0.388	-0.620

Table A.13 The impact of East Coast LNG exports on the national economy: Total employment formation (ths) – continued

	2015	2020	2025	2030	2035	2040
Services to mining	0.000	2.059	-0.647	-0.834	-1.171	-3.200
Meat and meat products	0.000	1.262	-9.148	-10.484	-11.542	-18.009
Dairy products	0.000	0.701	-4.549	-5.264	-5.796	-9.043
Fruit and vegetable products	0.000	0.120	-0.782	-0.905	-0.996	-1.554
Oils and fats	0.000	0.036	-0.267	-0.306	-0.337	-0.526
Flour mill products and cereal foods	0.000	0.242	-1.712	-1.965	-2.164	-3.377
Bakery products	0.000	0.605	-3.822	-4.429	-4.877	-7.616
Confectionery	0.000	0.146	-0.940	-1.088	-1.198	-1.870
Other food products	0.000	0.315	-2.127	-2.447	-2.695	-4.212
Soft drinks, cordials and syrups	0.000	0.112	-0.750	-0.867	-0.954	-1.486
Beer and malt	0.000	0.074	-0.459	-0.532	-0.586	-0.915
Wine, spirits and tobacco products (a)	0.000	0.100	-0.626	-0.724	-0.798	-1.248
Textile fibres, yarns and woven fabrics	0.000	0.014	-0.089	-0.102	-0.113	-0.178
Textile products	0.000	0.096	-0.565	-0.654	-0.722	-1.133
Knitting mill products	0.000	0.041	-0.256	-0.295	-0.326	-0.510
Clothing	0.000	0.186	-1.036	-1.199	-1.324	-2.087
Footwear	0.000	0.024	-0.130	-0.152	-0.168	-0.264
Leather and leather products	0.000	0.011	-0.051	-0.059	-0.065	-0.104
Sawmill products	0.000	0.081	-0.159	-0.197	-0.224	-0.382
Other wood products	0.000	0.315	-0.766	-0.911	-1.031	-1.742
Pulp, paper and paperboard	0.000	0.020	-0.105	-0.120	-0.133	-0.212
Paper containers and products	0.000	0.126	-0.861	-0.982	-1.084	-1.703
Printing and services to printing	0.000	0.542	-2.480	-2.883	-3.198	-5.107
Publishing, recorded media, etc.	0.000	0.478	-2.861	-3.299	-3.641	-5.726
Petroleum and coal products	0.000	0.275	-1.155	-1.352	-1.504	-2.418
Glass and glass products	0.000	0.121	-0.598	-0.688	-0.763	-1.219
Ceramic products	0.000	0.018	-0.027	-0.036	-0.042	-0.072
Cement, lime and concrete slurry	0.000	0.064	0.052	0.037	0.032	0.012
Plaster and other concrete products	0.000	0.042	0.159	0.155	0.163	0.227

Table A.13 The impact of East Coast LNG exports on the national economy: Total employment formation (ths) – continued

	2015	2020	2025	2030	2035	2040
Other non-metallic mineral products	0.000	0.055	-0.060	-0.076	-0.090	-0.170
Iron and steel	0.000	0.749	-1.117	-1.345	-1.559	-2.828
Structural metal products	0.000	0.357	-0.215	-0.294	-0.365	-0.776
Sheet metal products	0.000	0.079	-0.312	-0.359	-0.400	-0.652
Fabricated metal products	0.000	0.463	-0.803	-0.955	-1.099	-1.956
Motor vehicles and parts, other transport equipment	0.000	1.002	-5.043	-5.868	-6.488	-10.266
Ships and boats	0.000	0.028	-0.136	-0.157	-0.174	-0.277
Railway equipment	0.000	0.097	0.005	-0.011	-0.023	-0.093
Aircraft	0.000	0.113	-0.179	-0.219	-0.250	-0.444
Photographic and scientific equipment	0.000	0.186	-0.864	-1.009	-1.117	-1.776
Electronic equipment	0.000	0.174	-0.560	-0.665	-0.744	-1.212
Household appliances	0.000	0.223	-1.146	-1.335	-1.475	-2.329
Other electrical equipment	0.000	0.255	0.761	0.690	0.722	0.992
Agricultural, mining, etc. machinery	0.000	0.387	-0.315	-0.398	-0.480	-0.973
Other machinery and equipment	0.000	0.343	-0.566	-0.678	-0.780	-1.393
Prefabricated buildings	0.000	0.129	0.030	0.020	0.007	-0.075
Furniture	0.000	0.575	-3.104	-3.609	-3.985	-6.276
Other manufacturing	0.000	0.255	-1.333	-1.517	-1.685	-2.700
Electricity supply	0.000	0.627	41.056	42.510	46.193	70.731
Gas supply	0.000	0.175	0.659	0.578	0.607	0.871
Water supply, sewerage and drainage services	0.000	0.333	-1.717	-1.992	-2.205	-3.494
Residential building	0.000	0.187	0.083	0.035	0.016	-0.077
Other construction	0.000	0.489	0.091	-0.029	-0.090	-0.409
Construction trade services	0.000	5.699	10.736	9.891	10.081	12.245
Wholesale trade	0.000	3.638	-17.687	-20.242	-22.490	-36.102
Wholesale mechanical repairs	0.000	0.393	0.176	0.137	0.103	-0.087
Other wholesale repairs	0.000	0.917	-0.824	-1.068	-1.272	-2.476
Retail trade	0.000	10.433	-66.102	-76.590	-84.339	-131.692
Retail mechanical repairs	0.000	3.870	-12.971	-15.323	-17.111	-27.872

Table A.13 The impact of East Coast LNG exports on the national economy: Total employment formation (ths) – continued

	2015	2020	2025	2030	2035	2040
Other retail repairs	0.000	0.178	-1.011	-1.174	-1.295	-2.034
Accommodation, cafes and restaurants	0.000	4.627	-27.705	-32.149	-35.435	-55.489
Road transport	0.000	1.811	-10.521	-11.998	-13.284	-21.095
Rail, pipeline and other transport	0.000	1.595	0.062	-0.192	-0.393	-1.562
Water transport	0.000	0.115	-0.367	-0.420	-0.473	-0.790
Air and space transport	0.000	0.667	-3.522	-4.097	-4.527	-7.142
Services to transport, storage	0.000	1.374	-4.185	-4.810	-5.410	-9.041
Communication services	0.000	1.790	-8.192	-9.585	-10.622	-16.902
Finance	0.000	3.695	-13.364	-15.896	-17.690	-28.485
Ownership of dwellings	0.000	0.000	0.000	0.000	0.000	0.000
Other property services	0.000	2.074	-3.768	-4.577	-5.223	-9.085
Scientific research, technical and computer services	0.000	2.527	-6.278	-7.342	-8.316	-14.143
Legal, accounting, marketing and business management services	0.000	3.290	-12.487	-14.514	-16.199	-26.339
Other business services	0.000	1.622	-6.394	-7.413	-8.270	-13.423
Government administration	0.000	0.504	-2.316	-2.643	-2.941	-4.746
Defence	0.000	0.004	-0.020	-0.022	-0.025	-0.040
Education	0.000	2.312	-13.176	-15.362	-16.941	-26.552
Health services	0.000	2.107	-13.971	-16.184	-17.807	-27.729
Community services	0.000	0.322	-2.138	-2.478	-2.726	-4.243
Motion picture, radio and television services	0.000	0.599	-2.876	-3.341	-3.701	-5.890
Libraries, museums and the arts	0.000	0.441	-1.935	-2.286	-2.534	-4.029
Sport, gambling and recreational services	0.000	2.120	-10.832	-12.609	-13.928	-21.989
Personal services	0.000	1.774	-11.621	-13.467	-14.819	-23.087
Other services	0.000	0.889	-5.786	-6.707	-7.381	-11.505
Total	**0.000**	**81.816**	**-375.199**	**-434.261**	**-482.785**	**-774.619**

Table A.14 East Coast LNG expansion: Gross output formation by industry ($2009m)	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Constrained industries			
Basic chemicals	0.00	0.00	0.00
Paints	0.00	0.00	0.00
Medicinal and pharmaceutical products, pesticides	0.00	0.00	0.00
Soap and detergents	0.00	0.00	0.00
Cosmetics and toiletry preparations	0.00	0.00	0.00
Other chemical products	0.00	0.00	0.00
Rubber products	0.00	0.00	0.00
Plastic products	0.00	0.00	0.00
Basic non-ferrous metal and products	0.00	0.00	0.00
LNG	620.73	-124.15	496.58
Unconstrained industries			
Sheep	0.70	-0.23	0.47
Grains	1.06	-0.35	0.70
Beef cattle	1.94	-0.65	1.29
Dairy cattle	1.08	-0.37	0.72
Pigs	0.27	-0.09	0.18
Poultry	0.60	-0.20	0.40
Other agriculture	3.94	-1.32	2.62
Services to agriculture, hunting and trapping	0.92	-0.30	0.61
Forestry and logging	0.50	-0.12	0.37
Commercial fishing	0.63	-0.21	0.41
Coal	1.79	-0.45	1.34
Gas	5.80	-1.24	4.55
Oil	1.47	-0.43	1.03
Iron ores	0.20	-0.05	0.16
Non-ferrous metal ores	0.31	-0.08	0.24
Other mining	0.45	-0.11	0.34
Services to mining	15.45	-3.11	12.34
Meat and meat products	4.60	-1.55	3.05
Dairy products	3.54	-1.20	2.35
Fruit and vegetable products	1.12	-0.38	0.74
Oils and fats	0.44	-0.15	0.29
Flour mill products and cereal foods	1.83	-0.62	1.22
Bakery products	1.51	-0.51	1.00
Confectionery	1.15	-0.39	0.76
Other food products	2.69	-0.90	1.79
Soft drinks, cordials and syrups	1.48	-0.50	0.98
Beer and malt	1.26	-0.42	0.84
Wine, spirits and tobacco products (a)	1.44	-0.48	0.96
Textile fibres, yarns and woven fabrics	0.12	-0.04	0.08
Textile products	0.37	-0.12	0.25
Knitting mill products	0.26	-0.09	0.17

Table A.14 East Coast LNG expansion: Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Clothing	0.57	-0.18	0.39
Footwear	0.12	-0.04	0.08
Leather and leather products	0.09	-0.03	0.07
Sawmill products	0.54	-0.14	0.40
Other wood products	1.09	-0.28	0.81
Pulp, paper and paperboard	0.30	-0.09	0.21
Paper containers and products	0.90	-0.29	0.61
Printing and services to printing	2.88	-0.86	2.02
Publishing, recorded media, etc.	3.29	-1.05	2.24
Petroleum and coal products	6.35	-1.87	4.48
Glass and glass products	0.67	-0.20	0.47
Ceramic products	0.12	-0.03	0.08
Cement, lime and concrete slurry	0.83	-0.20	0.63
Plaster and other concrete products	0.43	-0.10	0.33
Other non-metallic mineral products	0.23	-0.05	0.17
Iron and steel	4.24	-1.00	3.24
Structural metal products	2.92	-0.66	2.26
Sheet metal products	0.91	-0.25	0.66
Fabricated metal products	2.23	-0.53	1.70
Motor vehicles and parts, other transport equipment	4.75	-1.48	3.27
Ships and boats	0.40	-0.12	0.28
Railway equipment	1.21	-0.27	0.95
Aircraft	1.39	-0.34	1.05
Photographic and scientific equipment	0.91	-0.28	0.64
Electronic equipment	0.83	-0.23	0.59
Household appliances	1.37	-0.43	0.94
Other electrical equipment	1.34	-0.36	0.98
Agricultural, mining, etc. machinery	1.79	-0.40	1.39
Other machinery and equipment	1.60	-0.38	1.22
Prefabricated buildings	0.85	-0.17	0.68
Furniture	1.26	-0.40	0.86
Other manufacturing	1.07	-0.30	0.76
Electricity supply	10.97	-3.21	7.76
Gas supply	1.10	-0.34	0.76
Water supply, sewerage and drainage services	4.06	-1.26	2.80
Residential building	1.94	-0.47	1.46
Other construction	3.52	-0.84	2.68
Construction trade services	19.47	-4.56	14.91
Wholesale trade	25.88	-7.38	18.50
Wholesale mechanical repairs	2.89	-0.61	2.28
Other wholesale repairs	5.51	-1.29	4.22
Retail trade	32.74	-10.99	21.75

Table A.14 East Coast LNG expansion: Gross output formation by industry ($2009m) – continued			
	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	**Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices**	**Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices**
Retail mechanical repairs	7.63	-2.15	5.48
Other retail repairs	0.44	-0.14	0.30
Accommodation, cafes and restaurants	16.97	-5.60	11.37
Road transport	9.58	-2.87	6.72
Rail, pipeline and other transport	10.02	-2.21	7.80
Water transport	1.13	-0.28	0.85
Air and space transport	4.99	-1.58	3.41
Services to transport, storage	13.62	-3.43	10.19
Communication services	15.22	-4.65	10.57
Finance	47.38	-14.02	33.36
Ownership of dwellings	4.72	-1.62	3.10
Other property services	31.27	-7.86	23.41
Scientific research, technical and computer services	11.85	-2.96	8.89
Legal, accounting, marketing and business management services	18.85	-5.24	13.61
Other business services	11.10	-3.10	8.01
Government administration	2.21	-0.61	1.60
Defence	0.03	-0.01	0.02
Education	9.51	-3.13	6.38
Health services	9.29	-3.18	6.11
Community services	1.16	-0.40	0.76
Motion picture, radio and television services	4.08	-1.24	2.85
Libraries, museums and the arts	1.11	-0.34	0.76
Sport, gambling and recreational services	7.78	-2.45	5.34
Personal services	3.71	-1.27	2.45
Other services	3.99	-1.36	2.63
Total	**1082.81**	**-256.45**	**-28757.76**

Table A.15 East Coast LNG expansion: Total employment formation (ths)	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Constrained industries			
Basic chemicals	0.00	0.00	0.00
Paints	0.00	0.00	0.00
Medicinal and pharmaceutical products, pesticides	0.00	0.00	0.00
Soap and detergents	0.00	0.00	0.00
Cosmetics and toiletry preparations	0.00	0.00	0.00
Other chemical products	0.00	0.00	0.00
Rubber products	0.00	0.00	0.00
Plastic products	0.00	0.00	0.00
Basic non-ferrous metal and products	0.00	0.00	0.00
LNG	0.12	-0.02	0.09
Unconstrained industries			
Sheep	0.01	0.00	0.01
Grains	0.01	0.00	0.01
Beef cattle	0.03	-0.01	0.02
Dairy cattle	0.01	0.00	0.01
Pigs	0.01	0.00	0.00
Poultry	0.01	0.00	0.00
Other agriculture	0.04	-0.01	0.02
Services to agriculture, hunting and trapping	0.01	0.00	0.00
Forestry and logging	0.00	0.00	0.00
Commercial fishing	0.00	0.00	0.00
Coal	0.00	0.00	0.00
Gas	0.00	0.00	0.00
Oil	0.00	0.00	0.00
Iron ores	0.00	0.00	0.00
Non-ferrous metal ores	0.00	0.00	0.00
Other mining	0.00	0.00	0.00
Services to mining	0.10	-0.02	0.08
Meat and meat products	0.07	-0.02	0.04
Dairy products	0.04	-0.01	0.02
Fruit and vegetable products	0.01	0.00	0.00
Oils and fats	0.00	0.00	0.00
Flour mill products and cereal foods	0.01	0.00	0.01
Bakery products	0.03	-0.01	0.02
Confectionery	0.01	0.00	0.01
Other food products	0.02	-0.01	0.01
Soft drinks, cordials and syrups	0.01	0.00	0.00
Beer and malt	0.00	0.00	0.00
Wine, spirits and tobacco products (a)	0.01	0.00	0.00
Textile fibres, yarns and woven fabrics	0.00	0.00	0.00
Textile products	0.01	0.00	0.00
Knitting mill products	0.00	0.00	0.00

Table A.15 East Coast LNG expansion: Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Clothing	0.01	0.00	0.01
Footwear	0.00	0.00	0.00
Leather and leather products	0.00	0.00	0.00
Sawmill products	0.00	0.00	0.00
Other wood products	0.02	0.00	0.01
Pulp, paper and paperboard	0.00	0.00	0.00
Paper containers and products	0.01	0.00	0.00
Printing and services to printing	0.03	-0.01	0.02
Publishing, recorded media, etc.	0.03	-0.01	0.02
Petroleum and coal products	0.01	0.00	0.01
Glass and glass products	0.01	0.00	0.00
Ceramic products	0.00	0.00	0.00
Cement, lime and concrete slurry	0.00	0.00	0.00
Plaster and other concrete products	0.00	0.00	0.00
Other non-metallic mineral products	0.00	0.00	0.00
Iron and steel	0.04	-0.01	0.03
Structural metal products	0.02	0.00	0.01
Sheet metal products	0.00	0.00	0.00
Fabricated metal products	0.02	-0.01	0.02
Motor vehicles and parts, other transport equipment	0.05	-0.02	0.04
Ships and boats	0.00	0.00	0.00
Railway equipment	0.00	0.00	0.00
Aircraft	0.01	0.00	0.00
Photographic and scientific equipment	0.01	0.00	0.01
Electronic equipment	0.01	0.00	0.01
Household appliances	0.01	0.00	0.01
Other electrical equipment	0.01	0.00	0.01
Agricultural, mining, etc. machinery	0.02	0.00	0.02
Other machinery and equipment	0.02	0.00	0.01
Prefabricated buildings	0.01	0.00	0.01
Furniture	0.03	-0.01	0.02
Other manufacturing	0.01	0.00	0.01
Electricity supply	0.03	-0.01	0.02
Gas supply	0.01	0.00	0.01
Water supply, sewerage and drainage services	0.02	-0.01	0.01
Residential building	0.01	0.00	0.01
Other construction	0.02	-0.01	0.02
Construction trade services	0.29	-0.07	0.22
Wholesale trade	0.19	-0.05	0.14
Wholesale mechanical repairs	0.02	0.00	0.02
Other wholesale repairs	0.05	-0.01	0.04
Retail trade	0.56	-0.19	0.37

Table A.15 East Coast LNG expansion: Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Retail mechanical repairs	0.20	-0.06	0.14
Other retail repairs	0.01	0.00	0.01
Accommodation, cafes and restaurants	0.25	-0.08	0.17
Road transport	0.10	-0.03	0.07
Rail, pipeline and other transport	0.08	-0.02	0.06
Water transport	0.01	0.00	0.00
Air and space transport	0.04	-0.01	0.02
Services to transport, storage	0.07	-0.02	0.05
Communication services	0.09	-0.03	0.07
Finance	0.19	-0.06	0.14
Ownership of dwellings	0.00	0.00	0.00
Other property services	0.11	-0.03	0.08
Scientific research, technical and computer services	0.13	-0.03	0.10
Legal, accounting, marketing and business management services	0.17	-0.05	0.12
Other business services	0.08	-0.02	0.06
Government administration	0.03	-0.01	0.02
Defence	0.00	0.00	0.00
Education	0.12	-0.04	0.08
Health services	0.11	-0.04	0.07
Community services	0.02	-0.01	0.01
Motion picture, radio and television services	0.03	-0.01	0.02
Libraries, museums and the arts	0.02	-0.01	0.02
Sport, gambling and recreational services	0.11	-0.04	0.08
Personal services	0.10	-0.03	0.06
Other services	0.05	-0.02	0.03
Total	**4.28**	**-1.25**	**3.03**

Appendix B: Input-output flow table with direct allocation of imports – Australia

Table B.1(a) Australia input-output flow table with direct allocation of imports – $2009m

	Sheep	Grains	Beef cattle	Dairy cattle	Pigs	Poultry	Other agriculture	Services to agriculture, hunting and trapping	Forestry and logging	Commercial fishing
Sheep	2.82	2.66	4.46	1.74	1.64	2.28	2.14	1.15	0.00	0.00
Grains	46.57	1725.26	95.11	50.94	15.51	35.12	29.84	2.74	0.03	0.02
Beef cattle	0.00	0.00	11.30	2.89	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	1.19	1.14	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	13.34	0.00	0.00	0.00	0.00
Other agriculture	161.23	0.34	527.58	122.40	23.88	0.28	359.74	1194.95	4.39	0.07
Services to agriculture, hunting and trapping	555.44	612.63	1295.55	295.68	11.84	46.84	1405.10	32.09	10.57	0.00
Forestry and logging	4.17	0.08	133.48	6.99	0.02	0.07	95.67	0.00	381.55	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	0.28	0.27	1.10	0.29	0.03	0.03	0.62	0.30	0.02	0.02
Gas	2.56	2.71	4.34	2.23	0.71	6.67	4.98	2.09	1.24	0.28
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.03	0.04	0.13	0.03	0.00	0.01	0.06	0.09	0.00	0.01
Non-ferrous metal ores	1.07	0.94	4.01	1.14	0.13	0.07	2.44	0.39	0.06	0.01
Other mining	0.04	0.06	0.08	0.03	0.02	0.03	0.50	0.02	0.00	0.00
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	1.22	0.78	10.83	16.71	2.77	12.27	11.05	8.39	0.14	4.55
Dairy products	5.76	1.32	47.85	64.06	34.55	25.38	14.81	1.41	0.26	8.64
Fruit and vegetable products	0.49	0.98	1.07	0.74	0.51	0.48	1.25	0.45	0.17	0.46
Oils and fats	1.67	0.35	7.66	6.88	8.39	5.10	4.16	0.31	0.12	1.86
Flour mill products and cereal foods	7.86	2.93	39.92	57.05	25.76	43.30	12.99	1.81	4.31	25.16
Bakery products	0.32	0.91	0.59	0.31	0.05	0.61	1.44	0.41	0.36	0.63
Confectionery	2.47	0.70	20.51	43.20	7.62	30.55	19.36	14.31	0.12	11.03
Other food products	26.80	3.52	199.02	379.30	65.82	275.07	108.87	67.11	0.45	98.05
Soft drinks, cordials and syrups	0.63	2.30	1.04	0.89	0.05	0.11	3.33	0.42	0.04	0.12
Beer and malt	0.40	1.16	0.61	0.51	0.07	0.07	0.51	0.30	0.09	0.17
Wine, spirits and tobacco products	3.90	1.30	34.84	4.61	0.71	0.55	15.33	3.88	2.74	5.34
Textile fibres, yarns and woven fabrics	0.20	0.64	0.45	0.21	0.06	0.09	1.00	0.28	0.13	0.34

Table B.1(a) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Sheep	Grains	Beef cattle	Dairy cattle	Pigs	Poultry	Other agriculture	Services to agriculture, hunting and trapping	Forestry and logging	Commercial fishing
Textile products	0.27	0.57	0.73	0.13	0.03	0.11	0.73	0.17	0.27	1.24
Knitting mill products	0.18	0.49	0.42	0.14	0.04	0.07	0.50	0.16	0.16	0.91
Clothing	0.88	2.27	1.66	1.91	0.13	0.32	2.66	0.81	0.94	1.72
Footwear	0.14	0.36	0.24	0.31	0.04	0.08	0.45	0.16	0.23	0.32
Leather and leather products	0.25	0.57	0.97	1.44	0.24	1.03	1.32	0.24	0.15	0.67
Sawmill products	0.95	0.71	0.94	0.73	0.18	0.12	0.82	0.36	0.22	0.42
Other wood products	1.08	1.61	1.77	0.75	0.47	0.73	1.95	1.13	3.42	9.37
Pulp, paper and paperboard	0.21	0.45	0.40	0.13	0.09	0.29	2.43	0.19	0.18	0.18
Paper containers and products	0.67	1.09	1.08	0.24	0.12	6.29	18.56	0.25	0.21	0.30
Printing and services to printing	1.17	3.55	12.87	0.71	0.34	0.17	10.47	1.24	0.69	0.93
Publishing, recorded media, etc.	2.18	6.47	5.55	1.67	0.20	0.33	6.84	0.78	0.81	0.87
Petroleum and coal products	91.55	138.70	61.52	43.43	3.65	17.52	193.32	8.72	33.48	82.31
Basic chemicals	93.73	263.20	226.97	66.85	4.32	4.86	557.99	63.41	2.47	3.19
Paints	1.15	2.24	4.33	0.66	0.33	0.67	3.91	1.15	0.75	3.30
Medicinal and pharmaceutical products, pesticides	30.50	38.54	81.04	25.36	3.29	6.01	80.92	20.16	6.45	0.52
Soap and detergents	0.59	1.31	0.67	0.14	0.06	0.10	1.57	1.78	0.54	0.28
Cosmetics and toiletry preparations	0.15	0.21	0.35	0.12	0.02	0.04	0.35	0.10	0.05	0.03
Other chemical products	1.95	7.03	12.74	1.73	0.91	0.39	3.21	0.90	2.89	0.85
Rubber products	0.59	2.90	0.85	0.26	0.05	0.10	7.98	0.17	0.16	0.87
Plastic products	2.10	3.07	2.21	2.09	0.27	5.51	26.56	1.32	1.01	10.00
Glass and glass products	0.86	1.28	0.83	0.18	0.03	0.11	1.04	0.25	0.37	0.65
Ceramic products	0.04	0.12	0.08	0.04	0.01	0.02	0.60	0.07	0.24	0.52
Cement, lime and concrete slurry	0.19	0.53	0.35	0.17	0.05	0.11	0.62	0.23	6.75	0.96
Plaster and other concrete products	0.20	0.39	0.37	0.15	0.09	0.14	0.44	0.16	4.24	0.84
Other non-metallic mineral products	0.20	0.72	0.28	0.09	0.02	0.02	2.26	0.09	2.49	1.25
Iron and steel	0.76	1.92	2.51	1.10	0.21	0.46	35.39	0.68	2.21	4.07
Basic non-ferrous metal and products	1.40	3.34	2.60	1.13	0.38	0.94	6.49	1.35	0.95	2.55
Structural metal products	1.39	3.70	4.32	1.92	0.55	2.12	36.34	1.28	6.03	13.18
Sheet metal products	0.71	2.25	1.10	1.35	0.12	0.51	8.94	0.25	0.80	3.05
Fabricated metal products	11.57	9.52	7.27	1.48	0.49	1.62	26.11	0.86	9.47	18.76
Motor vehicles and parts, other transport equipment	3.43	7.64	5.95	2.28	1.34	1.86	7.00	1.97	4.09	10.82
Ships and boats	0.21	0.37	0.40	0.16	0.08	0.14	0.32	0.68	0.35	27.97
Railway equipment	0.10	0.21	0.20	0.09	0.03	0.06	0.20	0.08	0.12	0.29

Table B.1(a) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Sheep	Grains	Beef cattle	Dairy cattle	Pigs	Poultry	Other agriculture	Services to agriculture, hunting and trapping	Forestry and logging	Commercial fishing
Aircraft	0.50	1.63	1.08	0.19	0.03	0.02	0.92	5.86	0.22	0.21
Photographic and scientific equipment	1.38	1.40	3.96	2.47	0.16	0.27	2.74	0.67	0.60	2.83
Electronic equipment	0.93	4.53	2.31	1.29	0.23	0.51	1.84	0.61	1.68	4.20
Household appliances	0.51	1.52	2.49	1.11	0.13	0.23	2.09	0.60	0.58	2.31
Other electrical equipment	1.17	2.31	4.21	1.72	0.44	0.69	4.74	1.07	4.97	9.83
Agricultural, mining, etc. machinery	5.53	44.16	14.67	3.79	0.74	2.85	12.72	1.89	9.33	13.23
Other machinery and equipment	2.04	6.54	4.21	2.07	0.42	0.79	26.54	1.35	11.87	20.01
Prefabricated buildings	0.07	0.21	0.16	0.07	0.01	0.04	0.31	0.09	0.20	0.16
Furniture	0.63	1.41	0.92	0.45	0.11	0.26	2.83	0.70	0.94	3.28
Other manufacturing	2.08	4.30	5.27	6.29	1.12	4.10	11.63	0.90	1.32	6.63
Electricity supply	10.55	21.13	49.89	28.06	4.27	13.19	36.49	3.04	1.14	4.92
Gas supply	1.89	2.12	2.43	1.37	0.65	0.83	2.76	1.46	0.07	0.24
Water supply, sewerage and drainage services	14.08	218.43	132.27	87.66	22.22	24.67	160.91	4.23	0.74	2.34
Residential building	3.14	5.66	12.95	2.90	0.98	1.80	6.26	7.46	0.92	0.78
Other construction	9.67	15.68	34.82	9.65	2.05	4.11	14.92	10.50	1.71	1.06
Construction trade services	70.44	73.77	130.75	41.79	35.60	58.35	60.89	23.77	10.08	10.21
Wholesale trade	244.23	673.79	345.56	163.55	28.07	68.28	658.64	206.46	118.43	193.82
Wholesale mechanical repairs	14.22	47.95	22.30	11.29	1.57	1.78	19.10	0.22	24.73	6.42
Other wholesale repairs	4.70	33.98	15.64	4.75	0.33	2.18	12.51	1.01	2.37	17.89
Retail trade	15.84	42.37	27.49	9.11	1.79	4.53	51.27	14.81	12.29	15.43
Retail mechanical repairs	56.64	54.78	85.84	28.03	1.99	7.60	82.55	3.38	61.81	41.48
Other retail repairs	2.24	1.15	4.09	1.34	1.22	1.87	1.67	0.71	0.00	0.00
Accommodation, cafes and restaurants	19.05	36.23	30.64	12.01	0.21	1.20	38.72	0.82	1.95	6.89
Road transport	119.31	418.02	299.53	173.54	28.86	74.05	280.38	64.63	23.19	36.93
Rail, pipeline and other transport	4.88	18.24	5.65	2.37	0.80	1.44	4.40	1.92	0.30	0.28
Water transport	0.38	0.61	0.08	0.02	0.02	0.02	0.44	0.04	0.13	6.35
Air and space transport	4.38	4.54	11.79	3.01	0.49	0.54	9.35	6.36	0.65	1.46
Services to transport, storage	28.65	233.79	52.43	12.99	2.77	43.73	38.93	0.55	2.37	12.67
Communication services	45.20	45.85	93.11	20.87	5.61	9.36	46.04	4.14	3.88	6.87
Finance	117.26	344.08	258.25	93.21	15.26	43.71	345.73	56.95	39.53	79.69
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	41.04	100.35	104.40	21.11	4.63	10.92	61.60	96.31	3.89	4.68
Scientific research, technical and computer services	21.93	68.65	109.25	6.27	2.01	2.08	114.97	8.49	0.39	0.84

Table B.1(a) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Sheep	Grains	Beef cattle	Dairy cattle	Pigs	Poultry	Other agriculture	Services to agriculture, hunting and trapping	Forestry and logging	Commercial fishing
Legal, accounting, marketing and business management services	99.12	160.64	212.32	40.35	29.62	28.86	104.69	15.28	1.72	9.14
Other business services	4.14	10.81	41.27	0.04	0.01	0.50	5.69	0.38	1.80	2.88
Government administration	3.75	5.03	3.55	0.41	0.06	0.20	9.21	0.73	1.25	3.69
Defence	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Education	0.40	2.58	2.79	0.53	0.11	0.70	4.09	0.83	0.28	1.90
Health services	1.65	0.01	21.78	8.45	0.61	2.68	0.97	2.43	0.16	1.01
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.55	0.86	0.00
Libraries, museums and the arts	0.57	0.80	12.64	0.07	0.01	0.02	0.31	0.08	7.27	0.12
Sport, gambling and recreational services	14.31	0.09	14.59	7.06	0.86	0.01	0.12	0.01	0.01	0.02
Personal services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	1.97
Other services	0.06	0.36	0.35	0.02	0.00	0.05	0.12	0.01	0.00	0.00
Total intermediate usage including imports	**2342**	**5978**	**5544**	**2265**	**450**	**1040**	**6109**	**2085**	**1024**	**1250**
Wages and salaries	541	466	914	439	131	163	2168	843	657	326
Gross surplus	1968	3614	4137	1699	390	847	5741	2200	517	560
Indirect taxes on production	185	393	267	179	29	50	407	117	63	114
Total gross output	**5035**	**10451**	**10861**	**4582**	**1000**	**2101**	**14424**	**5244**	**2262**	**2250**
Value added at factor cost to output ratio	0.53	0.43	0.49	0.51	0.55	0.50	0.58	0.60	0.55	0.44
Share of wages and mixed income in value added	0.81	0.76	0.82	0.82	0.84	0.80	0.79	0.77	0.80	0.68
Employment to gross output ratio	16.64	8.63	14.25	13.27	23.95	9.01	9.46	7.25	7.13	6.58
Foreign ownership ratio	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Direct tax rate on surplus	0.01	0.01	0.01	0.01	0.08	0.09	0.02	0.06	0.06	0.06
Indirect tax rate on production	0.06	0.08	0.04	0.07	0.04	0.04	0.04	0.03	0.04	0.11
Foreign income payout ratio	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Replacement depreciation to value added ratio	0.08	0.07	0.18	0.05	0.12	0.13	0.08	0.06	0.13	0.13
Net national product ratio	0.91	0.92	0.81	0.94	0.87	0.86	0.91	0.93	0.86	0.86
Domestic income distribution ratio	0.17	0.20	0.16	0.16	0.14	0.17	0.19	0.20	0.16	0.25

Table B.1(b) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Coal	Gas	LNG	Oil	Iron ores	Non-ferrous metal ores	Other mining	Services to mining	Meat and meat products	Dairy products
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1575.79	0.00
Grains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7479.29	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4062.56
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	651.23	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1165.84	0.00
Other agriculture	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	16.01
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forestry and logging	41.01	7.77	2.99	7.53	0.11	60.12	1.00	0.00	0.00	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	150.92	30.29	11.64	29.36	9.67	19.88	0.52	0.07	0.89	0.79
Gas	12.69	215.70	77.95	49.97	35.18	19.79	1.67	2.00	37.95	58.04
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	299.82	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	1.35	0.30	0.12	0.29	804.22	0.74	0.14	0.08	0.15	0.03
Non-ferrous metal ores	16.35	3.22	1.24	3.12	55.08	1108.46	5.87	16.40	0.43	0.08
Other mining	31.61	1.99	0.77	1.93	4.23	6.85	687.19	0.03	0.07	0.01
Services to mining	3243.55	622.23	239.13	603.08	4941.65	4236.04	38.20	147.94	0.00	0.00
Meat and meat products	2.44	0.42	0.16	0.41	1.57	1.97	0.12	0.64	1320.25	13.31
Dairy products	1.81	0.30	0.11	0.29	16.44	1.46	0.10	0.59	13.06	1983.16
Fruit and vegetable products	3.05	0.46	0.18	0.45	1.77	2.79	0.18	0.97	15.34	23.80
Oils and fats	1.20	0.18	0.07	0.18	0.61	1.11	0.06	0.42	3.03	11.30
Flour mill products and cereal foods	2.67	0.43	0.16	0.42	1.66	2.32	0.14	0.73	24.60	25.99
Bakery products	11.19	0.98	0.38	0.95	9.70	7.78	0.55	9.58	17.24	69.52
Confectionery	1.91	0.31	0.12	0.30	1.09	1.67	0.10	0.49	2.43	162.09
Other food products	8.22	1.43	0.55	1.39	8.55	6.93	0.61	2.34	62.32	154.13
Soft drinks, cordials and syrups	0.81	0.17	0.07	0.16	1.46	0.62	0.07	0.14	5.16	9.04
Beer and malt	3.35	0.77	0.30	0.75	6.29	7.01	0.20	0.89	0.75	4.96
Wine, spirits and tobacco products	6.11	2.67	1.03	2.59	6.92	6.10	0.43	1.20	20.50	2.34
Textile fibres, yarns and woven fabrics	3.00	0.45	0.17	0.44	3.36	2.35	0.16	1.02	0.59	2.59
Textile products	4.23	1.05	0.40	1.02	3.09	3.38	0.09	0.74	1.10	7.38
Knitting mill products	1.94	0.40	0.15	0.39	2.73	1.50	0.14	0.29	0.37	0.97
Clothing	12.11	2.01	0.77	1.95	5.19	10.11	0.47	1.35	2.67	6.60

Table B.1(b) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Coal	Gas	LNG	Oil	Iron ores	Non-ferrous metal ores	Other mining	Services to mining	Meat and meat products	Dairy products
Footwear	1.59	0.30	0.12	0.29	1.22	1.31	0.10	0.23	0.51	1.32
Leather and leather products	1.68	0.30	0.11	0.29	1.09	1.49	0.10	0.37	3.18	1.36
Sawmill products	7.21	1.20	0.46	1.16	3.24	3.17	0.15	0.70	0.79	1.60
Other wood products	45.06	9.02	3.47	8.74	38.76	30.52	1.83	4.59	1.76	9.42
Pulp, paper and paperboard	4.62	0.84	0.32	0.82	2.14	3.26	0.13	18.01	15.65	37.75
Paper containers and products	7.43	1.75	0.67	1.70	5.51	5.01	0.31	3.10	97.82	201.03
Printing and services to printing	42.11	10.63	4.09	10.31	16.72	26.74	2.34	24.95	11.38	34.98
Publishing, recorded media, etc.	17.68	5.35	2.06	5.19	6.92	13.45	0.52	9.91	3.64	11.51
Petroleum and coal products	537.32	47.85	18.39	46.38	293.63	524.75	25.50	159.67	13.20	62.35
Basic chemicals	116.48	20.45	7.86	19.82	57.52	140.73	4.45	17.00	8.64	44.15
Paints	7.93	1.46	0.56	1.41	5.00	6.73	0.23	1.05	0.30	1.14
Medicinal and pharmaceutical products, pesticides	13.72	3.09	1.19	2.99	6.13	12.85	0.45	3.45	2.67	6.70
Soap and detergents	5.00	0.64	0.24	0.62	3.72	6.47	0.20	1.37	3.41	11.10
Cosmetics and toiletry preparations	0.59	0.16	0.06	0.15	1.13	0.39	0.05	0.10	0.16	0.45
Other chemical products	259.85	43.36	16.67	42.03	144.63	142.80	10.53	3.50	0.96	4.31
Rubber products	36.17	6.30	2.42	6.10	7.49	29.41	1.01	2.19	0.18	0.46
Plastic products	33.95	6.02	2.31	5.84	16.80	32.65	1.16	10.20	23.31	503.84
Glass and glass products	17.17	2.26	0.87	2.20	13.10	13.08	0.50	4.56	0.43	0.68
Ceramic products	2.14	0.25	0.10	0.24	1.46	4.15	0.15	1.65	0.18	1.47
Cement, lime and concrete slurry	15.39	3.13	1.20	3.04	14.24	31.92	0.80	20.99	0.56	1.62
Plaster and other concrete products	15.00	1.98	0.76	1.92	14.91	18.14	0.28	2.72	0.26	1.13
Other non-metallic mineral products	13.54	4.02	1.54	3.89	15.59	8.21	0.63	4.59	0.17	0.95
Iron and steel	289.72	47.23	18.15	45.77	182.16	156.23	5.20	257.88	1.57	5.78
Basic non-ferrous metal and products	66.79	24.27	9.33	23.53	86.94	78.09	4.24	25.55	3.11	27.85
Structural metal products	223.84	45.85	17.62	44.44	217.37	259.69	8.55	175.22	1.29	3.41
Sheet metal products	48.38	8.77	3.37	8.50	24.99	56.76	1.06	17.95	2.75	134.96
Fabricated metal products	224.89	46.10	17.72	44.68	108.22	159.01	7.40	34.13	5.09	8.81
Motor vehicles and parts, other transport equipment	75.23	16.94	6.51	16.42	47.72	57.85	5.26	18.40	3.39	9.02
Ships and boats	10.01	1.89	0.73	1.83	9.32	6.03	0.38	1.93	1.58	1.00
Railway equipment	13.92	4.83	1.85	4.68	4.55	2.23	0.26	0.26	0.20	0.39
Aircraft	147.12	27.85	10.70	26.99	15.03	8.71	2.38	16.06	0.10	0.69
Photographic and scientific equipment	26.28	5.97	2.29	5.78	14.45	18.45	0.86	3.19	1.28	7.04
Electronic equipment	11.94	5.30	2.04	5.14	16.43	10.19	0.61	8.83	1.41	7.74

Table B.1(b) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Coal	Gas	LNG	Oil	Iron ores	Non-ferrous metal ores	Other mining	Services to mining	Meat and meat products	Dairy products
Household appliances	17.61	5.55	2.13	5.38	7.82	13.58	1.12	4.44	0.81	4.37
Other electrical equipment	58.14	11.45	4.40	11.10	34.89	38.15	3.04	5.61	3.63	21.19
Agricultural, mining, etc. machinery	287.42	51.61	19.84	50.03	118.37	259.25	18.44	11.49	1.56	7.78
Other machinery and equipment	215.63	34.76	13.36	33.69	95.87	196.27	10.31	26.31	8.81	16.57
Prefabricated buildings	132.33	32.96	12.67	31.95	82.80	92.89	8.32	2.66	0.24	0.53
Furniture	21.86	4.28	1.64	4.15	16.11	18.75	0.97	4.09	1.60	5.18
Other manufacturing	38.29	8.53	3.28	8.27	39.40	39.55	1.94	11.30	9.26	29.74
Electricity supply	410.33	79.29	30.47	76.85	224.80	481.93	2.50	4.01	130.75	193.52
Gas supply	6.83	1.50	0.58	1.46	19.79	14.87	0.35	0.03	2.32	4.22
Water supply, sewerage and drainage services	70.33	8.70	3.34	8.43	275.95	179.62	13.38	1.85	28.91	32.02
Residential building	99.82	24.67	9.48	23.91	211.46	77.86	18.28	44.79	4.57	3.00
Other construction	274.01	59.39	22.82	57.56	842.41	194.27	85.23	60.64	6.18	4.05
Construction trade services	1221.53	304.97	117.20	295.59	5167.95	1003.91	192.47	326.54	15.09	49.52
Wholesale trade	1677.97	237.85	91.41	230.53	925.22	1582.16	88.21	468.73	383.49	1162.12
Wholesale mechanical repairs	176.85	95.04	36.53	92.12	138.95	67.05	9.24	246.94	9.08	6.96
Other wholesale repairs	454.67	140.62	54.04	136.29	138.12	100.77	15.69	157.33	25.01	8.61
Retail trade	171.55	30.07	11.56	29.14	107.04	107.94	9.37	45.46	212.50	128.82
Retail mechanical repairs	175.58	86.96	33.42	84.28	103.17	146.53	34.47	113.23	18.62	14.28
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	124.71	33.37	12.83	32.35	89.35	64.64	7.67	113.50	3.50	2.61
Road transport	405.57	65.09	25.02	63.09	152.81	281.41	49.11	92.31	1064.24	483.67
Rail, pipeline and other transport	1926.32	342.66	131.69	332.12	119.70	55.36	0.52	3.80	11.79	15.80
Water transport	45.69	10.00	3.84	9.69	8.07	21.98	1.75	359.92	1.05	3.44
Air and space transport	93.25	17.14	6.59	16.61	86.89	72.95	4.55	89.98	2.22	1.99
Services to transport, storage	1169.62	225.91	86.82	218.96	231.79	173.66	8.91	98.91	93.79	164.35
Communication services	191.90	49.15	18.89	47.64	74.33	367.76	13.30	127.98	44.48	101.62
Finance	1141.70	295.41	113.53	286.32	723.89	952.44	176.74	327.21	80.25	81.10
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	1721.27	407.16	156.47	394.63	1083.64	533.21	30.22	72.19	338.34	54.20
Scientific research, technical and computer services	165.77	17.00	6.53	16.47	55.03	229.07	3.40	3668.41	39.03	69.18
Legal, accounting, marketing and business management services	1028.24	120.96	46.49	117.24	302.53	844.39	15.18	312.48	41.33	208.89
Other business services	334.76	36.58	14.06	35.45	106.82	545.69	10.51	314.49	128.55	96.96

Table B.1(b) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Coal	Gas	LNG	Oil	Iron ores	Non-ferrous metal ores	Other mining	Services to mining	Meat and meat products	Dairy products
Government administration	121.14	24.00	9.22	23.26	175.98	98.03	6.49	13.19	9.75	3.59
Defence	0.11	0.02	0.01	0.02	0.11	0.08	0.00	1.30	0.14	0.13
Education	67.21	18.04	6.93	17.48	33.97	47.21	4.40	34.85	14.91	34.45
Health services	0.03	0.00	0.00	0.00	0.03	0.02	0.00	1.51	29.60	0.11
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	5.68	2.29	0.88	2.22	20.81	54.46	0.55	18.65	7.15	48.76
Libraries, museums and the arts	0.00	0.00	0.00	0.00	0.05	1.38	0.03	49.17	0.00	0.00
Sport, gambling and recreational services	75.46	52.34	20.11	50.73	8.84	39.30	0.03	94.28	0.00	0.00
Personal services	0.23	0.00	0.00	0.00	0.00	0.00	0.00	6.79	0.00	0.00
Other services	44.27	0.00	0.00	0.00	10.11	11.83	0.11	0.00	3.36	0.38
Total intermediate usage including imports	**23076**	**4822**	**1848**	**4815**	**20960**	**19037**	**1820**	**9326**	**15582**	**11555**
Wages and salaries	4373	1486	211	1225	967	3249	769	5376	3644	1384
Gross surplus	29574	3761	7998	8488	11711	16205	1574	511	134	108
Indirect taxes on production	9	74	28	74	513	599	37	293	451	282
Total gross output	**57032**	**10143**	**10086**	**14601**	**34152**	**39091**	**4200**	**15506**	**19811**	**13329**
Value added at factor cost to output ratio	0.60	0.52	0.82	0.67	0.39	0.51	0.57	0.40	0.21	0.13
Share of wages and mixed income in value added	0.13	0.31	0.05	0.14	0.08	0.17	0.37	0.93	0.92	0.85
Employment to gross output ratio	1.29	0.82	0.19	0.47	0.95	2.10	3.71	6.67	14.71	10.59
Foreign ownership ratio	0.50	0.80	0.70	0.80	0.55	0.60	0.30	0.40	0.45	0.55
Direct tax rate on surplus	0.18	0.21	0.30	0.21	0.25	0.23	0.26	0.22	0.58	0.16
Indirect tax rate on production	-0.01	0.00	0.00	0.00	0.02	0.02	0.01	0.03	0.07	0.09
Foreign income payout ratio	0.36	0.46	0.46	0.50	0.35	0.36	0.15	0.03	0.03	0.07
Replacement depreciation to value added ratio	0.13	0.30	0.24	0.30	0.11	0.26	0.17	0.15	0.13	0.23
Net national product ratio	0.51	0.24	0.29	0.21	0.54	0.38	0.68	0.83	0.84	0.70
Domestic income distribution ratio	0.36	0.11	0.15	0.14	0.28	0.24	0.34	0.04	0.04	0.05

Table B.1(c) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Fruit and vegetable products	Oils and fats	Flour mill products and cereal foods	Bakery products	Confectionery	Other food products	Soft drinks, cordials and syrups	Beer and malt	Wine, spirits and tobacco products	Textile fibres, yarns and woven fabrics
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	418.17
Grains	12.80	153.60	1693.59	4.85	13.04	598.87	10.87	522.89	74.14	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	12.44	0.00	3.63	0.00	0.00	0.00	0.00
Other agriculture	573.50	22.99	3.66	40.84	49.84	1567.91	214.38	6.88	583.85	0.01
Services to agriculture, hunting and trapping	0.00	7.13	0.00	0.00	0.00	3.20	0.00	0.00	0.00	21.06
Forestry and logging	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial fishing	0.00	25.76	0.63	1.58	0.30	356.64	0.00	0.00	0.00	0.00
Coal	3.55	0.67	4.31	0.56	0.92	8.32	0.04	0.49	0.14	0.38
Gas	21.46	7.47	19.29	15.73	5.25	57.53	26.17	10.15	2.78	0.03
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.00	0.00	0.02	0.00	0.00	0.02	0.01	0.00	0.00	0.00
Non-ferrous metal ores	0.01	0.00	0.05	0.01	0.01	0.07	0.02	0.01	0.01	0.00
Other mining	0.01	0.46	0.03	0.29	0.04	169.98	0.00	0.00	0.00	0.00
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	34.85	70.59	7.46	362.52	5.93	446.80	0.34	0.92	1.07	0.07
Dairy products	34.16	33.63	132.74	235.56	598.75	170.25	7.65	0.27	4.42	0.03
Fruit and vegetable products	128.50	3.73	27.11	35.38	19.77	38.17	1.51	0.78	7.84	0.04
Oils and fats	6.94	82.49	31.14	31.27	7.98	53.45	0.66	0.14	2.59	0.02
Flour mill products and cereal foods	133.22	19.05	1009.40	526.35	110.04	150.15	2.33	2.18	5.51	0.05
Bakery products	3.88	0.51	6.94	59.80	122.06	103.56	0.39	0.24	1.42	0.04
Confectionery	15.34	2.03	90.71	66.75	99.57	75.05	0.55	0.74	1.82	0.04
Other food products	90.65	71.26	166.24	178.23	183.51	570.49	53.45	13.58	26.97	0.15
Soft drinks, cordials and syrups	33.79	3.48	16.07	11.31	25.99	21.26	1.18	2.96	133.27	0.01
Beer and malt	1.82	0.19	2.86	1.78	3.93	15.37	9.99	234.75	6.81	0.01
Wine, spirits and tobacco products	3.23	1.31	4.26	1.79	79.11	6.21	1.61	1.32	244.34	0.07
Textile fibres, yarns and woven fabrics	0.28	0.52	0.63	1.20	0.36	3.79	0.21	0.15	0.45	4.32
Textile products	0.59	0.36	1.38	0.83	1.41	3.50	0.60	1.29	0.84	2.29
Knitting mill products	0.20	0.11	0.43	0.20	0.13	0.72	0.14	0.11	0.14	3.06
Clothing	1.14	0.80	2.01	1.83	1.09	5.33	0.83	0.68	0.85	0.13

Table B.1(c) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Fruit and vegetable products	Oils and fats	Flour mill products and cereal foods	Bakery products	Confectionery	Other food products	Soft drinks, cordials and syrups	Beer and malt	Wine, spirits and tobacco products	Textile fibres, yarns and woven fabrics
Footwear	0.25	0.14	0.46	0.21	0.29	0.77	0.21	0.16	0.19	0.03
Leather and leather products	0.23	0.16	0.26	0.70	0.24	1.67	0.18	0.18	0.18	0.15
Sawmill products	0.38	0.16	0.63	0.26	0.33	1.00	0.28	0.25	0.40	0.04
Other wood products	2.33	1.05	1.34	0.54	0.58	2.09	4.72	1.17	1.36	0.11
Pulp, paper and paperboard	6.84	2.90	7.94	2.35	7.38	11.63	5.87	6.60	7.99	0.04
Paper containers and products	56.92	20.46	60.93	18.29	36.17	123.75	49.01	41.07	67.57	0.04
Printing and services to printing	3.67	1.41	24.82	4.44	4.21	12.32	5.68	4.77	4.52	1.28
Publishing, recorded media, etc.	1.62	0.45	2.86	1.38	3.39	7.49	1.15	1.55	1.56	0.14
Petroleum and coal products	34.01	3.68	18.87	6.87	3.14	34.42	15.63	6.35	5.13	0.39
Basic chemicals	10.15	9.92	11.82	12.47	9.17	45.74	37.50	2.30	3.68	1.83
Paints	0.16	0.06	0.30	0.20	0.14	1.35	0.15	0.09	0.13	0.03
Medicinal and pharmaceutical products, pesticides	1.17	0.62	1.99	1.03	1.59	4.09	1.15	0.88	2.51	0.15
Soap and detergents	0.26	0.10	0.52	0.32	0.41	1.56	0.35	0.19	0.23	0.18
Cosmetics and toiletry preparations	0.21	0.19	0.16	0.21	0.15	0.51	0.31	0.03	0.03	0.01
Other chemical products	0.39	0.27	0.91	0.49	1.02	1.75	0.70	1.59	0.62	0.07
Rubber products	0.15	0.12	0.33	0.12	0.54	0.67	0.09	0.07	0.09	0.02
Plastic products	82.06	44.77	42.29	35.78	34.92	142.44	189.32	6.47	8.94	0.69
Glass and glass products	100.47	0.71	0.29	0.16	1.26	14.66	98.97	35.95	53.67	0.02
Ceramic products	0.08	0.25	0.19	0.11	0.11	0.45	0.07	0.05	0.09	0.01
Cement, lime and concrete slurry	0.41	0.31	0.70	0.33	0.57	2.36	0.28	0.23	0.27	0.05
Plaster and other concrete products	0.17	0.12	0.26	0.12	0.39	0.83	0.15	0.12	0.15	0.02
Other non-metallic mineral products	0.23	0.29	0.58	0.30	1.24	0.86	0.04	0.03	0.08	0.04
Iron and steel	2.35	0.48	1.84	1.12	0.90	7.58	3.15	3.29	0.51	0.10
Basic non-ferrous metal and products	3.74	1.40	3.34	1.91	4.67	24.99	4.23	2.40	1.17	0.55
Structural metal products	6.55	0.31	0.75	0.35	0.71	4.18	6.43	4.59	3.27	0.06
Sheet metal products	89.94	5.36	4.63	0.90	1.05	30.39	176.01	90.57	3.02	0.03
Fabricated metal products	2.46	0.67	1.86	1.14	3.22	5.69	4.11	4.58	1.63	0.11
Motor vehicles and parts, other transport equipment	1.98	1.01	3.14	1.66	3.04	5.26	4.58	1.91	1.87	0.14
Ships and boats	0.18	0.14	0.71	0.26	0.75	2.57	0.91	0.24	0.25	0.01
Railway equipment	0.09	0.03	0.13	0.06	0.28	0.28	0.08	0.05	0.08	0.01
Aircraft	0.03	0.01	0.08	0.05	0.04	0.13	0.07	0.06	0.06	0.00
Photographic and scientific equipment	0.73	0.39	1.25	0.67	0.54	3.24	0.68	0.61	0.56	0.07
Electronic equipment	0.82	0.45	1.38	0.91	1.70	7.70	20.92	1.94	1.40	0.08

Table B.1(c) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Fruit and vegetable products	Oils and fats	Flour mill products and cereal foods	Bakery products	Confectionery	Other food products	Soft drinks, cordials and syrups	Beer and malt	Wine, spirits and tobacco products	Textile fibres, yarns and woven fabrics
Household appliances	0.49	0.26	0.83	0.40	0.47	1.70	0.32	1.00	0.31	0.04
Other electrical equipment	1.11	0.58	2.81	1.67	2.07	5.12	3.02	2.70	2.23	0.11
Agricultural, mining, etc. machinery	1.13	0.44	1.28	0.63	0.61	2.96	1.04	2.24	0.57	0.08
Other machinery and equipment	5.08	1.15	3.64	4.66	3.44	15.66	14.74	2.45	1.17	0.12
Prefabricated buildings	0.11	0.04	0.17	0.07	0.08	0.32	0.07	0.09	0.10	0.01
Furniture	1.11	0.35	1.17	1.33	3.72	2.56	3.45	0.89	0.56	0.16
Other manufacturing	4.51	7.92	10.19	30.80	8.80	39.44	5.72	3.53	3.83	0.83
Electricity supply	25.55	13.35	67.09	22.19	22.46	74.60	14.75	27.84	7.75	4.56
Gas supply	17.52	6.39	16.22	13.33	3.92	44.98	21.97	8.72	1.54	0.05
Water supply, sewerage and drainage services	14.97	3.53	15.91	3.49	7.89	29.42	6.99	26.34	1.87	4.92
Residential building	1.25	0.98	2.70	1.10	2.29	5.53	1.78	0.70	2.27	0.04
Other construction	1.69	1.32	3.65	1.49	3.09	7.35	2.39	0.94	2.99	0.05
Construction trade services	14.06	13.28	28.53	13.61	33.90	32.89	14.25	11.72	13.02	0.84
Wholesale trade	256.71	87.05	352.17	188.32	181.41	663.59	168.97	148.98	180.63	25.90
Wholesale mechanical repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other wholesale repairs	0.52	0.84	5.56	36.21	2.09	24.87	11.47	3.89	2.64	1.20
Retail trade	28.66	7.13	74.95	223.70	161.67	269.10	11.64	9.31	53.03	1.73
Retail mechanical repairs	27.40	13.85	52.14	13.81	17.75	72.46	65.97	11.19	3.51	1.05
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	6.22	4.72	15.34	26.09	22.38	66.55	158.16	111.28	80.09	0.34
Road transport	196.62	78.00	379.00	96.47	62.86	535.91	80.28	177.23	67.85	21.73
Rail, pipeline and other transport	8.36	2.12	29.22	5.66	2.17	24.52	7.07	21.73	3.97	2.78
Water transport	1.46	1.97	2.00	0.88	2.02	33.02	1.17	0.53	2.38	0.20
Air and space transport	9.85	5.40	17.88	3.84	5.24	17.40	2.68	2.09	2.97	0.21
Services to transport, storage	15.49	43.50	122.16	42.28	46.19	411.25	133.92	113.20	51.45	1.73
Communication services	12.81	5.59	77.64	13.57	11.80	52.85	26.60	10.13	13.77	1.56
Finance	37.33	29.99	103.52	36.09	19.16	259.28	26.98	129.33	31.77	8.61
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	6.76	4.37	18.42	22.97	5.11	37.14	24.47	3.29	6.25	0.39
Scientific research, technical and computer services	40.07	2.83	50.28	32.61	11.23	149.39	41.25	1.24	28.04	1.24
Legal, accounting, marketing and business management services	34.60	22.22	175.27	26.56	90.05	220.34	64.42	54.79	54.79	2.01
Other business services	122.36	6.77	42.08	35.94	9.25	120.98	49.70	5.45	62.61	0.75

Table B.1(c) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Fruit and vegetable products	Oils and fats	Flour mill products and cereal foods	Bakery products	Confectionery	Other food products	Soft drinks, cordials and syrups	Beer and malt	Wine, spirits and tobacco products	Textile fibres, yarns and woven fabrics
Government administration	0.78	0.89	9.81	2.34	3.87	36.77	14.61	2.84	2.40	0.03
Defence	0.21	0.02	0.29	0.15	0.03	1.13	0.37	0.00	0.13	0.00
Education	3.94	4.36	8.35	8.00	6.74	12.70	9.58	6.39	3.40	0.10
Health services	0.10	0.06	0.31	0.21	0.42	0.84	0.87	0.14	4.33	0.00
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	9.19	0.00	10.63	5.93	18.76	55.10	24.27	5.85	5.50	0.00
Libraries, museums and the arts	0.00	0.00	0.00	0.00	1.57	0.00	0.00	0.23	0.31	0.00
Sport, gambling and recreational services	0.14	0.01	0.04	0.08	0.06	2.33	0.50	0.36	7.06	0.00
Personal services	0.22	0.14	0.33	0.61	0.27	1.35	1.21	0.13	0.12	0.01
Other services	2.20	0.19	4.75	1.01	1.36	3.26	0.68	0.33	1.17	0.00
Total intermediate usage including imports	**2832**	**1291**	**5581**	**3002**	**2710**	**9080**	**2184**	**2011**	**2229**	**558**
Wages and salaries	440	71	578	1135	948	2329	632	442	1352	405
Gross surplus	776	345	442	364	236	821	1401	1407	2827	109
Indirect taxes on production	96	55	133	124	105	292	94	74	384	144
Total gross output	**4144**	**1762**	**6734**	**4625**	**4000**	**12522**	**4312**	**3933**	**6791**	**1216**
Value added at factor cost to output ratio	0.32	0.27	0.17	0.35	0.32	0.27	0.49	0.49	0.67	0.54
Share of wages and mixed income in value added	0.35	0.17	0.54	0.78	0.78	0.73	0.31	0.24	0.31	0.62
Employment to gross output ratio	5.77	4.40	7.08	21.45	6.80	6.26	4.05	3.14	3.71	5.99
Foreign ownership ratio	0.37	0.42	0.43	0.23	0.32	0.10	0.50	0.29	0.15	0.14
Direct tax rate on surplus	0.02	0.01	0.06	0.09	0.07	0.19	0.15	0.15	0.03	0.02
Indirect tax rate on production	0.05	0.09	0.06	0.06	0.06	0.05	0.03	0.03	0.08	0.27
Foreign income payout ratio	0.22	0.31	0.18	0.05	0.06	0.02	0.28	0.18	0.09	0.04
Replacement depreciation to value added ratio	0.13	0.10	0.17	0.22	0.21	0.14	0.13	0.05	0.11	0.09
Net national product ratio	0.65	0.59	0.66	0.74	0.73	0.84	0.59	0.77	0.80	0.87
Domestic income distribution ratio	0.38	0.42	0.23	0.15	0.13	0.21	0.28	0.43	0.52	0.24

Table B.1(d) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Textile products	Knitting mill products	Clothing	Footwear	Leather and leather products	Sawmill products	Other wood products	Pulp, paper and paperboard	Paper containers and products	Printing and services to printing
Sheep	0.01	0.00	0.08	0.00	41.29	0.00	0.00	0.00	0.00	0.00
Grains	0.02	0.01	0.01	0.02	0.01	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	1.93	0.07	0.22	0.14	6.11	0.00	0.00	0.00	0.00	0.61
Services to agriculture, hunting and trapping	0.28	8.99	3.91	0.04	42.09	0.00	0.00	0.00	0.00	0.00
Forestry and logging	0.00	0.00	0.00	0.00	0.00	747.20	164.62	74.11	13.12	3.76
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	9.00	0.43	0.01	0.00	0.01	0.21	1.70	2.02	1.50	0.38
Gas	7.69	1.01	0.86	0.42	0.22	12.29	21.49	34.76	39.60	14.18
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.00	0.00	0.00	0.00	0.00	0.03	0.04	0.01	0.02	0.08
Non-ferrous metal ores	0.01	0.01	0.01	0.00	0.01	1.12	0.36	0.02	0.07	0.26
Other mining	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.01	0.03
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	12.93	0.11	18.95	0.02	325.32	0.27	0.47	0.09	0.21	0.70
Dairy products	0.07	0.07	0.11	0.03	0.05	0.24	0.37	0.06	0.17	0.41
Fruit and vegetable products	0.14	0.09	0.26	0.03	1.71	0.26	0.42	0.08	0.19	0.63
Oils and fats	0.08	0.04	0.06	0.01	0.02	0.13	0.16	0.06	0.07	0.30
Flour mill products and cereal foods	0.10	0.11	0.19	0.04	0.08	0.34	0.51	0.09	0.25	0.78
Bakery products	0.08	0.09	0.16	0.03	0.07	0.24	0.41	0.07	0.18	0.62
Confectionery	0.07	0.08	0.14	0.03	0.06	0.22	0.37	0.06	0.16	0.55
Other food products	0.94	0.25	0.75	0.13	4.19	1.16	2.55	0.37	0.81	2.03
Soft drinks, cordials and syrups	0.08	0.02	0.03	0.01	0.01	0.07	0.10	0.14	0.23	2.15
Beer and malt	0.07	0.06	0.03	0.01	0.01	0.32	0.24	0.04	0.12	0.49
Wine, spirits and tobacco products	0.51	0.43	0.05	0.01	0.02	1.31	1.79	0.31	0.44	4.40
Textile fibres, yarns and woven fabrics	22.20	14.29	20.17	0.65	0.34	0.23	0.71	0.06	1.06	2.29
Textile products	3.07	6.05	11.20	0.22	0.51	0.26	3.53	0.05	1.12	1.55
Knitting mill products	7.17	45.85	39.29	0.14	0.11	0.17	0.24	0.04	1.52	0.86
Clothing	1.38	3.37	37.10	3.23	3.23	0.81	1.49	0.20	0.69	6.20

Table B.1(d) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Textile products	Knitting mill products	Clothing	Footwear	Leather and leather products	Sawmill products	Other wood products	Pulp, paper and paperboard	Paper containers and products	Printing and services to printing
Footwear	0.10	0.12	3.21	11.62	2.69	0.23	0.41	0.04	0.12	0.99
Leather and leather products	2.02	0.58	5.40	8.52	77.73	0.30	0.31	0.06	0.20	0.56
Sawmill products	0.16	0.12	0.18	0.08	0.11	318.93	539.16	25.54	1.34	1.04
Other wood products	1.24	0.34	1.91	0.24	0.39	38.14	397.97	0.68	1.80	15.12
Pulp, paper and paperboard	0.51	0.35	0.61	0.21	0.06	4.88	4.98	5.40	28.76	148.32
Paper containers and products	0.73	2.52	3.16	0.91	0.28	4.85	6.75	1.81	71.55	69.79
Printing and services to printing	23.16	24.62	10.76	0.88	0.74	7.45	17.03	6.35	35.87	373.65
Publishing, recorded media, etc.	0.93	0.84	10.90	0.28	2.44	1.94	10.72	19.85	34.30	43.88
Petroleum and coal products	1.89	0.36	0.60	0.12	0.22	11.84	8.63	5.93	2.31	10.66
Basic chemicals	17.21	25.93	4.83	0.89	5.79	22.06	47.29	15.10	63.39	126.17
Paints	0.19	0.25	0.10	0.04	0.06	1.18	19.87	0.21	1.55	5.27
Medicinal and pharmaceutical products, pesticides	0.95	0.56	0.78	0.58	0.56	4.80	4.15	3.59	3.96	7.58
Soap and detergents	1.34	0.11	0.13	0.05	0.12	2.02	1.68	1.29	2.14	4.85
Cosmetics and toiletry preparations	0.03	0.01	0.02	0.01	0.01	0.13	0.09	0.04	0.09	0.08
Other chemical products	6.00	0.44	0.28	1.50	0.29	6.15	64.21	2.09	13.11	79.28
Rubber products	0.31	0.02	0.10	0.39	0.04	0.16	0.85	0.22	2.03	4.73
Plastic products	14.14	9.45	4.81	1.67	0.93	4.73	26.62	2.35	31.08	265.05
Glass and glass products	1.59	0.07	4.21	1.59	0.55	7.69	15.00	0.08	1.15	3.48
Ceramic products	0.08	0.02	0.18	0.08	0.02	0.17	0.62	0.55	0.86	0.48
Cement, lime and concrete slurry	0.15	0.17	0.18	0.08	0.08	1.74	1.88	0.42	0.98	1.00
Plaster and other concrete products	0.08	0.05	0.10	0.05	0.04	0.92	29.72	0.46	0.79	1.97
Other non-metallic mineral products	0.44	0.21	0.05	0.01	0.01	2.47	5.53	0.72	0.64	0.99
Iron and steel	1.66	0.43	0.29	0.15	0.15	3.93	41.36	2.48	2.66	6.72
Basic non-ferrous metal and products	5.84	2.62	1.34	0.77	0.77	13.21	71.81	2.40	13.28	72.79
Structural metal products	5.47	0.16	0.30	0.06	0.19	1.92	112.06	29.03	0.59	2.47
Sheet metal products	0.42	0.07	0.19	0.06	0.07	0.52	16.76	0.21	1.63	6.76
Fabricated metal products	3.10	7.68	0.51	0.26	0.25	10.98	53.45	6.47	4.73	16.28
Motor vehicles and parts, other transport equipment	0.96	0.39	0.56	0.21	0.23	1.94	9.09	0.54	2.16	8.09
Ships and boats	0.04	0.04	0.05	0.02	0.03	1.20	1.33	0.43	1.29	3.36
Railway equipment	0.02	0.03	0.03	0.01	0.02	0.10	0.17	0.02	0.11	0.25
Aircraft	0.01	0.01	0.02	0.00	0.01	0.03	0.05	0.23	0.18	0.09
Photographic and scientific equipment	0.20	0.14	0.85	0.14	0.18	10.90	12.85	0.34	1.14	12.35
Electronic equipment	0.18	0.20	0.33	0.17	0.20	10.04	11.69	0.34	0.93	8.86

Table B.1(d) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Textile products	Knitting mill products	Clothing	Footwear	Leather and leather products	Sawmill products	Other wood products	Pulp, paper and paperboard	Paper containers and products	Printing and services to printing
Household appliances	0.08	0.09	0.15	0.03	0.07	8.07	9.27	0.09	0.24	6.48
Other electrical equipment	0.43	0.24	0.39	0.09	0.16	10.95	14.51	4.89	4.24	12.69
Agricultural, mining, etc. machinery	0.16	0.17	0.67	0.06	0.14	10.35	13.11	0.16	0.46	8.63
Other machinery and equipment	0.30	0.25	1.18	0.34	0.29	11.64	16.73	4.10	1.10	10.57
Prefabricated buildings	0.14	0.05	0.12	0.04	0.02	0.25	2.36	0.02	0.13	0.30
Furniture	0.79	0.67	1.09	0.31	0.30	0.74	11.01	0.20	0.67	1.60
Other manufacturing	12.83	6.13	37.44	1.00	0.63	5.36	36.53	1.67	11.09	19.99
Electricity supply	10.21	12.10	3.22	1.44	2.02	85.97	130.66	57.67	80.66	109.78
Gas supply	6.23	0.64	0.68	0.12	0.18	6.15	11.92	25.50	31.94	11.61
Water supply, sewerage and drainage services	4.28	11.64	1.12	0.25	1.49	3.29	12.55	11.18	13.54	17.38
Residential building	0.85	0.62	0.18	0.09	0.21	4.79	5.08	0.37	2.70	8.08
Other construction	1.14	0.83	0.24	0.12	0.28	9.05	9.46	0.57	3.90	11.12
Construction trade services	3.57	4.14	2.42	1.29	1.51	63.01	54.18	4.43	14.29	28.23
Wholesale trade	50.85	53.40	98.73	20.51	40.23	226.90	323.00	45.86	117.14	375.61
Wholesale mechanical repairs	0.00	0.00	0.00	0.00	0.00	12.32	8.92	0.70	3.16	0.00
Other wholesale repairs	10.15	3.19	0.82	6.35	4.71	57.68	67.89	6.87	24.56	47.52
Retail trade	9.64	118.90	57.37	2.74	3.24	14.68	25.55	8.39	24.97	69.28
Retail mechanical repairs	15.54	11.50	0.00	8.90	5.31	25.33	14.96	4.27	37.01	147.03
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	8.95	7.55	7.30	0.13	3.10	14.68	20.64	2.06	14.21	84.91
Road transport	20.91	17.58	19.76	13.54	52.95	237.59	128.80	36.86	58.35	126.20
Rail, pipeline and other transport	2.14	16.41	0.25	0.49	0.51	8.73	3.08	6.72	5.98	4.82
Water transport	3.11	1.14	2.58	1.09	0.33	8.66	3.05	9.27	10.32	5.49
Air and space transport	2.70	4.94	7.03	0.40	1.02	2.24	9.69	0.50	5.20	79.96
Services to transport, storage	5.36	3.40	21.75	3.52	3.32	279.77	261.89	26.22	217.09	126.76
Communication services	8.58	6.94	8.93	1.96	1.96	30.36	77.84	3.43	16.84	190.35
Finance	20.83	11.03	12.49	2.42	5.80	45.67	75.02	15.47	33.21	167.58
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	2.69	1.93	8.64	1.67	4.18	244.87	190.88	2.13	19.76	153.39
Scientific research, technical and computer services	42.99	24.21	8.26	1.44	5.98	27.55	42.09	1.71	28.75	226.54
Legal, accounting, marketing and business management services	37.53	18.85	19.13	5.26	8.00	98.48	170.73	9.10	174.78	425.72
Other business services	6.66	14.71	31.08	7.57	8.61	103.11	154.47	8.98	93.05	409.15

Table B.1(d) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Textile products	Knitting mill products	Clothing	Footwear	Leather and leather products	Sawmill products	Other wood products	Pulp, paper and paperboard	Paper containers and products	Printing and services to printing
Government administration	0.58	0.60	0.07	0.01	0.06	7.82	7.34	1.47	13.86	34.27
Defence	0.08	0.19	0.03	0.01	0.02	0.11	0.13	0.00	0.12	0.42
Education	1.91	1.35	16.06	0.28	0.79	5.13	9.23	1.56	6.27	26.60
Health services	0.02	0.06	5.31	5.53	0.01	4.79	7.61	0.18	1.73	8.84
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	0.72	0.18	1.02	0.19	0.00	1.50	31.55	0.00	0.62	1.51
Libraries, museums and the arts	0.00	0.00	2.00	0.00	0.00	0.00	0.00	0.00	0.76	2.22
Sport, gambling and recreational services	0.03	0.02	0.02	0.00	0.01	0.04	0.06	0.01	0.04	0.25
Personal services	0.39	0.07	0.00	0.00	0.00	0.40	0.32	0.07	0.55	2.26
Other services	0.00	0.00	0.68	0.04	0.20	1.33	1.37	1.75	6.48	9.71
Total intermediate usage including imports	**725**	**740**	**999**	**245**	**728**	**3232**	**4258**	**717**	**2046**	**5934**
Wages and salaries	672	81	732	111	151	448	1626	240	1481	3227
Gross surplus	145	51	418	77	191	768	608	473	610	1743
Indirect taxes on production	51	30	83	16	24	93	120	57	125	251
Total gross output	**1594**	**902**	**2232**	**449**	**1094**	**4542**	**6612**	**1488**	**4262**	**11154**
Value added at factor cost to output ratio	0.54	0.18	0.55	0.45	0.33	0.29	0.36	0.52	0.52	0.47
Share of wages and mixed income in value added	1.01	0.65	0.79	0.64	0.50	0.39	0.87	0.32	0.69	0.69
Employment to gross output ratio	13.65	8.43	17.35	10.39	5.84	7.68	14.87	3.47	7.45	9.88
Foreign ownership ratio	0.03	0.09	0.02	0.15	0.22	0.05	0.15	0.29	0.27	0.05
Direct tax rate on surplus	0.25	0.04	0.08	0.08	0.02	0.06	0.13	0.02	0.03	0.06
Indirect tax rate on production	0.05	0.15	0.06	0.07	0.04	0.04	0.03	0.07	0.05	0.03
Foreign income payout ratio	0.00	0.03	0.00	0.05	0.11	0.02	0.02	0.16	0.08	0.01
Replacement depreciation to value added ratio	0.15	0.09	0.06	0.09	0.06	0.09	0.18	0.54	0.13	0.13
Net national product ratio	0.85	0.89	0.93	0.87	0.83	0.88	0.80	0.29	0.79	0.86
Domestic income distribution ratio	0.00	0.26	0.18	0.27	0.36	0.49	0.10	0.39	0.20	0.27

Table B.1(e) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Publishing, recorded media, etc.	Petroleum and coal products	Basic chemicals	Paints	Medicinal and pharmaceutical products, pesticides	Soap and detergents	Cosmetics and toiletry preparations	Other chemical products	Rubber products	Plastic products
Sheep	0.00	0.00	4.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grains	0.00	0.00	8.95	2.30	90.72	10.00	1.85	5.74	0.01	0.03
Beef cattle	0.00	0.00	23.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	2.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	4.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	1.98	0.00	0.52	0.68	0.05	0.25	0.04	0.20	3.14	55.40
Services to agriculture, hunting and trapping	0.00	0.00	7.66	3.90	0.00	8.89	5.40	2.86	0.00	0.00
Forestry and logging	0.66	0.00	17.31	0.12	10.12	0.00	1.57	9.86	0.00	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	0.10	316.26	101.18	0.01	0.38	0.01	0.01	0.45	0.01	0.12
Gas	4.58	-4821.55	75.97	0.82	8.15	2.17	0.35	5.61	0.30	14.04
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	5844.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.02	0.35	0.03	0.00	0.01	0.00	0.00	0.00	0.00	0.02
Non-ferrous metal ores	0.10	10.72	118.82	1.20	0.05	0.02	0.00	0.09	0.01	0.11
Other mining	0.01	3.98	75.39	0.03	0.03	0.40	0.07	4.16	0.03	0.14
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	0.20	0.47	104.51	6.50	17.95	103.67	6.38	16.42	0.05	0.77
Dairy products	0.12	0.36	9.41	0.19	5.17	2.10	0.79	1.27	0.03	0.65
Fruit and vegetable products	0.17	0.60	2.05	0.18	1.04	0.48	0.12	0.45	0.04	0.68
Oils and fats	0.07	5.05	12.35	3.36	13.17	6.68	1.07	0.92	0.06	0.35
Flour mill products and cereal foods	0.20	0.57	39.21	1.48	3.03	2.69	0.75	3.45	0.05	0.83
Bakery products	0.16	0.44	1.86	0.06	0.57	0.14	0.04	0.19	0.04	0.66
Confectionery	0.14	0.39	2.13	0.08	0.51	0.14	0.04	0.21	0.03	0.59
Other food products	0.73	2.53	39.63	8.03	23.49	15.11	5.40	15.19	0.14	2.37
Soft drinks, cordials and syrups	0.38	0.40	8.32	0.02	0.97	1.41	0.51	2.57	0.01	0.28
Beer and malt	1.69	0.47	0.47	0.04	0.16	0.07	0.02	0.07	0.02	0.27
Wine, spirits and tobacco products	9.72	2.35	10.79	0.48	2.87	0.53	0.17	0.60	0.18	1.14
Textile fibres, yarns and woven fabrics	1.94	0.67	3.77	0.07	1.81	0.11	0.33	0.58	1.03	5.44
Textile products	0.70	0.44	1.81	0.13	0.33	0.31	0.21	0.34	0.16	2.26
Knitting mill products	0.98	0.54	0.66	0.03	0.26	0.07	0.03	0.09	0.02	2.95
Clothing	3.31	1.43	4.49	0.17	1.66	0.49	0.28	0.69	0.73	5.89

Table B.1(e) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Publishing, recorded media, etc.	Petroleum and coal products	Basic chemicals	Paints	Medicinal and pharmaceutical products, pesticides	Soap and detergents	Cosmetics and toiletry preparations	Other chemical products	Rubber products	Plastic products
Footwear	0.40	0.34	0.74	0.05	0.37	0.12	0.03	0.18	0.10	0.76
Leather and leather products	0.13	0.26	0.73	0.07	0.30	0.13	0.04	0.16	0.21	0.74
Sawmill products	1.24	0.83	1.90	0.07	1.11	0.20	0.09	1.34	0.06	1.87
Other wood products	1.56	6.56	17.79	0.56	3.63	2.08	0.47	3.47	0.71	19.22
Pulp, paper and paperboard	176.63	1.64	2.90	0.15	10.87	2.32	0.45	1.27	0.40	8.86
Paper containers and products	8.72	1.20	22.54	2.66	110.93	19.01	3.94	9.79	0.37	28.04
Printing and services to printing	135.08	5.43	18.01	2.06	16.55	2.52	1.31	4.91	1.15	24.69
Publishing, recorded media, etc.	203.77	10.17	31.72	1.88	34.52	1.73	1.65	16.43	3.43	44.21
Petroleum and coal products	10.34	399.46	200.51	14.46	5.59	3.59	2.39	18.96	6.99	29.97
Basic chemicals	4.97	351.43	1388.08	58.61	58.97	94.98	33.06	172.44	23.88	1102.74
Paints	0.21	4.82	45.64	2.58	1.21	0.95	0.14	2.96	0.13	5.58
Medicinal and pharmaceutical products, pesticides	0.29	4.10	710.67	2.07	98.70	2.47	0.60	6.97	1.29	9.31
Soap and detergents	0.14	10.01	35.63	1.77	2.17	3.16	0.70	5.24	0.39	3.65
Cosmetics and toiletry preparations	0.03	0.91	2.64	0.03	0.44	0.04	0.04	0.19	0.02	0.22
Other chemical products	9.13	26.59	81.52	1.60	6.34	2.93	1.77	102.90	0.74	40.42
Rubber products	1.07	1.48	5.63	0.18	0.61	0.09	0.04	0.70	13.79	18.05
Plastic products	11.49	17.83	133.65	4.36	135.75	72.31	24.31	39.88	5.55	259.92
Glass and glass products	0.51	1.65	5.14	0.11	35.39	8.30	0.28	7.18	0.15	14.59
Ceramic products	0.52	0.63	1.12	0.08	1.95	0.22	0.08	1.25	0.02	1.30
Cement, lime and concrete slurry	0.48	5.42	7.03	0.54	1.98	1.76	0.24	2.30	0.28	2.64
Plaster and other concrete products	0.40	1.30	8.10	0.56	0.71	0.17	0.06	0.50	0.17	5.92
Other non-metallic mineral products	0.59	0.46	3.00	1.14	0.84	0.60	0.21	1.02	0.51	6.18
Iron and steel	1.46	3.13	17.51	0.71	3.82	0.90	0.34	2.84	0.72	9.35
Basic non-ferrous metal and products	4.66	55.07	131.31	6.08	12.95	16.92	1.88	12.09	2.99	185.01
Structural metal products	1.00	1.67	6.04	0.95	3.16	0.77	0.13	1.42	0.19	23.38
Sheet metal products	0.87	7.93	14.61	13.98	35.89	1.83	2.17	9.49	0.12	13.24
Fabricated metal products	16.74	3.46	52.10	2.78	24.60	4.51	1.31	14.62	7.68	29.18
Motor vehicles and parts, other transport equipment	1.30	3.18	5.11	0.37	2.85	0.87	0.33	1.35	0.78	9.03
Ships and boats	6.30	4.66	3.65	0.16	0.44	0.29	0.07	0.43	0.04	0.50
Railway equipment	0.09	0.87	0.30	0.01	0.19	0.03	0.02	0.05	0.04	0.87
Aircraft	0.08	0.34	0.10	0.00	0.05	0.01	0.00	0.01	0.00	0.26
Photographic and scientific equipment	13.22	29.51	6.80	0.11	3.31	0.32	0.11	0.51	0.10	2.45
Electronic equipment	10.98	26.58	5.73	0.12	0.98	0.30	0.09	1.26	0.23	1.97

Table B.1(e) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Publishing, recorded media, etc.	Petroleum and coal products	Basic chemicals	Paints	Medicinal and pharmaceutical products, pesticides	Soap and detergents	Cosmetics and toiletry preparations	Other chemical products	Rubber products	Plastic products
Household appliances	8.72	21.70	4.39	0.08	0.91	0.22	0.05	0.28	0.07	2.13
Other electrical equipment	12.74	28.32	9.02	0.21	2.75	0.55	0.18	0.98	4.86	9.36
Agricultural, mining, etc. machinery	11.02	27.82	9.39	0.15	1.97	0.48	0.12	0.72	0.09	1.70
Other machinery and equipment	11.16	28.36	14.38	0.75	4.46	1.37	0.37	2.85	0.37	6.50
Prefabricated buildings	0.08	0.19	0.36	0.01	0.18	0.04	0.01	0.08	0.01	0.54
Furniture	0.66	0.93	2.94	0.16	1.41	0.29	0.09	0.58	0.27	1.78
Other manufacturing	2.55	5.99	17.62	1.09	11.44	4.27	1.64	7.89	0.52	32.11
Electricity supply	21.64	84.85	164.76	2.61	40.78	6.38	3.07	20.08	7.53	154.35
Gas supply	3.68	24.68	41.45	0.59	6.46	1.60	0.23	4.01	0.10	8.72
Water supply, sewerage and drainage services	5.75	62.36	54.44	0.86	16.99	3.20	3.06	20.94	1.52	10.52
Residential building	5.46	39.76	5.17	0.44	5.70	0.76	0.25	0.91	0.90	5.33
Other construction	7.72	164.87	6.97	0.59	7.68	1.02	0.34	1.23	1.22	7.19
Construction trade services	14.56	735.40	32.56	5.16	21.22	10.55	3.16	11.44	8.01	35.76
Wholesale trade	107.35	606.03	845.70	35.16	385.31	80.88	23.92	111.75	23.11	395.23
Wholesale mechanical repairs	0.00	0.00	1.87	0.53	1.01	1.03	0.31	1.12	0.00	0.00
Other wholesale repairs	94.95	2.84	48.42	3.02	4.31	1.71	0.28	1.05	7.00	78.60
Retail trade	51.50	42.31	69.81	2.81	52.62	11.12	2.38	13.11	2.44	45.36
Retail mechanical repairs	76.80	33.13	72.66	4.04	24.56	7.79	1.82	15.81	0.46	23.16
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	89.46	131.70	63.86	3.18	76.70	7.31	5.36	20.12	0.65	19.13
Road transport	43.72	126.10	363.08	12.71	160.72	41.78	11.39	51.06	8.02	178.81
Rail, pipeline and other transport	4.66	17.14	25.23	0.42	6.58	1.48	0.37	2.49	0.21	66.14
Water transport	5.22	191.07	16.16	0.16	2.17	0.66	0.29	6.16	1.11	9.22
Air and space transport	55.06	17.51	18.53	1.61	17.28	3.68	1.19	3.17	0.65	10.11
Services to transport, storage	356.83	135.90	383.77	7.33	232.04	10.43	2.87	103.22	4.72	67.35
Communication services	170.76	135.89	50.37	8.69	41.24	7.65	2.16	18.39	3.56	65.56
Finance	295.24	77.38	116.25	5.88	101.67	15.98	4.36	16.14	10.52	79.55
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	553.54	204.32	22.22	5.35	32.66	4.29	2.72	11.95	1.85	42.95
Scientific research, technical and computer services	157.07	23.54	126.68	6.73	340.76	24.98	5.38	14.23	18.84	126.30
Legal, accounting, marketing and business management services	442.18	780.98	317.70	15.51	335.97	10.69	4.32	28.98	21.79	294.02
Other business services	392.91	583.24	134.30	2.75	510.35	38.26	12.74	32.26	109.60	256.18

Table B.1(e) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Publishing, recorded media, etc.	Petroleum and coal products	Basic chemicals	Paints	Medicinal and pharmaceutical products, pesticides	Soap and detergents	Cosmetics and toiletry preparations	Other chemical products	Rubber products	Plastic products
Government administration	114.98	25.43	98.31	5.44	2.85	7.27	1.75	5.60	0.51	9.02
Defence	0.35	0.10	0.77	0.04	1.18	0.09	0.03	0.06	0.10	0.51
Education	8.05	51.17	19.34	2.44	14.48	0.77	1.25	4.75	1.19	14.17
Health services	38.08	1.18	4.83	1.66	76.87	0.16	0.03	0.17	0.10	0.77
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	113.70	14.89	6.54	4.43	32.56	4.13	9.07	0.00	0.05	11.86
Libraries, museums and the arts	51.32	0.00	0.24	1.11	0.00	14.16	1.14	1.82	0.00	0.00
Sport, gambling and recreational services	9.12	0.17	1.77	0.01	0.22	0.83	0.18	0.06	1.76	1.96
Personal services	8.33	0.00	0.75	0.15	0.53	0.11	0.08	0.09	0.22	0.87
Other services	9.41	1.47	4.75	0.15	8.76	0.97	0.37	0.88	0.44	4.86
Total intermediate usage including imports	**5559**	**22850**	**8908**	**462**	**4088**	**1019**	**278**	**1488**	**432**	**5880**
Wages and salaries	3639	618	1642	532	1671	261	164	727	374	1963
Gross surplus	2523	2022	1242	82	711	259	115	145	195	776
Indirect taxes on production	369	364	235	34	173	36	21	53	44	192
Total gross output	**12090**	**25854**	**12027**	**1111**	**6644**	**1575**	**578**	**2413**	**1046**	**8810**
Value added at factor cost to output ratio	0.54	0.12	0.26	0.58	0.38	0.35	0.52	0.38	0.59	0.33
Share of wages and mixed income in value added	0.59	0.24	0.56	0.85	0.68	0.49	0.57	0.82	0.63	0.70
Employment to gross output ratio	7.72	2.27	2.67	10.14	8.08	5.80	6.76	9.72	8.69	9.14
Foreign ownership ratio	0.03	0.80	0.50	0.48	0.65	0.60	0.45	0.28	0.90	0.20
Direct tax rate on surplus	0.04	0.02	0.12	0.06	0.41	0.21	0.21	0.34	0.06	0.13
Indirect tax rate on production	0.05	0.02	0.04	0.05	0.05	0.04	0.06	0.04	0.07	0.04
Foreign income payout ratio	0.01	0.58	0.19	0.07	0.16	0.24	0.16	0.04	0.30	0.05
Replacement depreciation to value added ratio	0.01	0.23	0.24	0.14	0.15	0.13	0.15	0.37	0.09	0.20
Net national product ratio	0.98	0.19	0.58	0.79	0.69	0.63	0.70	0.59	0.61	0.75
Domestic income distribution ratio	0.37	0.15	0.19	0.08	0.09	0.16	0.19	0.11	0.03	0.21

Table B.1(f) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Glass and glass products	Ceramic products	Cement, lime and concrete slurry	Plaster and other concrete products	Other non-metallic mineral products	Iron and steel	Basic non-ferrous metal and products	Structural metal products	Sheet metal products	Fabricated metal products
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.21	0.14
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forestry and logging	0.00	0.00	0.00	0.00	0.00	0.65	8.80	0.00	0.00	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	0.00	0.00	9.65	0.19	0.00	263.70	8.85	0.54	0.17	3.23
Gas	102.59	97.20	550.65	7.25	22.22	162.42	212.82	8.77	5.21	12.14
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.01	0.00	0.04	0.01	0.00	837.81	1.93	30.04	0.03	16.00
Non-ferrous metal ores	0.05	0.00	0.12	72.63	14.97	24.75	25675.69	0.27	0.10	10.53
Other mining	40.68	0.00	683.28	184.78	19.97	582.95	220.53	2.72	0.07	2.67
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	0.19	0.00	0.46	0.26	0.03	1.58	1.40	1.11	0.42	0.60
Dairy products	0.11	0.00	0.28	0.15	0.02	0.91	1.17	0.63	0.17	0.51
Fruit and vegetable products	0.19	0.00	0.41	0.23	0.03	1.14	1.25	0.93	0.24	0.47
Oils and fats	0.08	0.00	0.17	0.21	0.01	0.58	0.49	0.34	0.11	0.22
Flour mill products and cereal foods	0.20	0.00	0.50	0.30	0.04	1.42	1.50	1.13	0.29	0.59
Bakery products	0.16	0.00	0.40	0.22	0.02	1.23	1.25	0.92	0.23	0.47
Confectionery	0.14	0.00	0.36	0.20	0.02	1.04	1.09	0.81	0.21	0.41
Other food products	0.49	0.00	1.19	1.26	0.10	3.75	3.29	4.52	1.52	2.41
Soft drinks, cordials and syrups	0.06	0.00	0.10	0.06	0.01	0.36	0.28	0.20	0.06	0.11
Beer and malt	0.08	0.00	0.26	0.09	0.01	0.45	0.34	0.31	0.14	0.18
Wine, spirits and tobacco products	1.10	0.00	2.21	0.95	0.13	1.29	0.92	1.17	0.70	0.87
Textile fibres, yarns and woven fabrics	0.20	0.00	0.28	0.51	0.04	2.55	1.05	1.08	0.65	0.83
Textile products	0.46	0.00	0.72	1.17	0.04	2.40	1.74	7.43	0.34	4.98
Knitting mill products	0.10	0.00	0.19	1.54	0.02	0.97	0.64	0.61	1.29	0.39
Clothing	0.59	0.00	1.14	1.10	0.11	4.06	3.51	5.74	1.86	3.39

Table B.1(f) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Glass and glass products	Ceramic products	Cement, lime and concrete slurry	Plaster and other concrete products	Other non-metallic mineral products	Iron and steel	Basic non-ferrous metal and products	Structural metal products	Sheet metal products	Fabricated metal products
Footwear	0.19	0.00	0.30	0.26	0.03	0.76	0.73	0.71	0.27	0.86
Leather and leather products	1.63	0.00	0.46	0.36	0.06	0.44	0.64	1.04	0.19	4.43
Sawmill products	1.05	0.00	0.47	1.75	0.07	7.58	1.81	91.38	2.25	8.48
Other wood products	9.78	0.00	1.34	4.78	0.34	37.23	8.99	48.45	4.54	22.32
Pulp, paper and paperboard	0.85	0.00	5.03	2.30	0.10	1.96	0.79	1.86	0.44	1.56
Paper containers and products	3.83	0.00	52.97	9.97	0.84	4.12	2.47	5.31	1.24	11.82
Printing and services to printing	4.80	0.00	13.08	10.07	1.09	21.59	9.47	34.81	7.19	16.39
Publishing, recorded media, etc.	1.18	0.00	13.15	4.33	0.33	17.26	10.98	56.89	6.85	9.02
Petroleum and coal products	13.83	5.79	196.84	16.09	8.60	116.62	51.87	33.91	15.22	26.73
Basic chemicals	82.80	0.00	5.64	29.24	11.55	51.37	77.78	58.12	13.67	48.82
Paints	3.53	0.00	0.25	0.88	0.22	36.81	1.34	2.98	3.20	5.93
Medicinal and pharmaceutical products, pesticides	2.33	0.00	0.79	1.57	0.36	6.20	5.39	1.96	1.14	3.52
Soap and detergents	4.13	0.00	0.36	2.26	0.50	3.42	2.06	0.54	0.49	2.15
Cosmetics and toiletry preparations	0.38	0.00	0.05	0.08	0.01	0.32	0.21	0.25	0.04	0.09
Other chemical products	3.57	0.00	2.00	5.55	2.40	11.27	3.04	6.60	1.43	8.14
Rubber products	0.20	0.00	0.09	0.48	0.11	1.75	7.01	1.85	1.51	6.76
Plastic products	12.24	0.00	4.58	10.39	3.54	19.14	18.96	47.13	11.77	16.74
Glass and glass products	309.44	0.00	0.90	1.63	0.81	1.67	2.91	170.33	1.84	8.03
Ceramic products	0.90	0.00	74.46	33.96	1.45	6.29	2.23	7.34	0.17	5.99
Cement, lime and concrete slurry	8.55	0.00	1038.10	481.95	18.61	64.79	42.79	8.56	1.61	5.11
Plaster and other concrete products	9.49	0.00	92.16	112.04	9.88	10.25	6.57	19.57	1.24	1.99
Other non-metallic mineral products	22.40	0.00	20.86	13.75	3.54	5.17	6.06	12.31	2.06	9.35
Iron and steel	20.12	0.00	29.12	71.25	3.04	2416.38	237.64	1992.57	334.37	750.88
Basic non-ferrous metal and products	129.53	0.00	8.90	31.74	2.84	2125.18	15296.53	1395.96	1131.20	955.96
Structural metal products	22.62	0.00	8.62	115.15	14.35	65.54	74.88	1299.37	39.11	258.57
Sheet metal products	0.69	0.00	0.31	3.40	1.31	42.47	12.46	60.17	43.16	22.04
Fabricated metal products	5.86	0.00	3.47	12.61	1.71	117.47	47.28	406.52	64.17	153.78
Motor vehicles and parts, other transport equipment	20.52	0.00	4.03	4.74	1.07	21.71	11.71	18.57	8.25	13.76
Ships and boats	0.66	0.00	3.62	0.74	0.08	2.60	1.14	3.99	0.54	1.87
Railway equipment	0.06	0.00	0.12	0.38	0.02	3.32	0.71	0.41	0.22	0.45
Aircraft	0.04	0.00	0.06	0.05	0.00	0.34	0.19	0.11	0.03	0.05
Photographic and scientific equipment	0.34	0.00	0.85	1.08	0.06	6.67	5.93	2.76	0.88	1.69
Electronic equipment	0.90	0.00	1.16	0.82	0.12	5.26	3.13	18.81	1.76	3.31

Table B.1(f) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Glass and glass products	Ceramic products	Cement, lime and concrete slurry	Plaster and other concrete products	Other non-metallic mineral products	Iron and steel	Basic non-ferrous metal and products	Structural metal products	Sheet metal products	Fabricated metal products
Household appliances	2.42	0.00	0.57	0.50	0.06	2.61	1.92	2.39	0.96	1.40
Other electrical equipment	1.67	0.00	2.73	2.75	0.25	18.56	9.25	21.83	8.12	13.51
Agricultural, mining, etc. machinery	0.65	0.00	5.25	6.38	0.21	15.15	14.28	14.24	1.54	19.84
Other machinery and equipment	3.70	0.00	2.94	10.83	0.50	27.15	42.17	22.37	9.54	13.60
Prefabricated buildings	0.11	0.00	0.22	0.93	0.21	1.31	1.30	38.54	0.63	1.34
Furniture	0.86	0.00	0.93	1.44	0.51	11.75	7.69	13.57	2.58	8.53
Other manufacturing	3.79	0.00	2.53	5.40	1.48	71.17	160.88	27.82	6.45	8.91
Electricity supply	80.90	44.40	204.79	33.97	42.42	995.46	529.79	67.54	26.89	80.18
Gas supply	77.97	74.03	431.96	3.31	14.81	104.62	133.25	6.52	4.08	9.14
Water supply, sewerage and drainage services	7.92	0.00	16.50	9.61	0.80	94.92	20.66	6.46	1.71	5.88
Residential building	1.58	0.00	3.88	1.99	0.14	32.21	11.77	8.28	3.11	3.51
Other construction	2.18	0.00	6.11	2.77	0.19	43.55	15.94	11.18	4.20	4.73
Construction trade services	12.25	0.00	17.65	10.16	1.67	133.17	92.10	32.09	14.03	19.06
Wholesale trade	97.80	0.00	238.06	133.43	15.24	735.32	1176.60	551.40	164.68	290.43
Wholesale mechanical repairs	0.17	0.00	12.99	5.60	0.23	6.29	0.80	0.00	0.00	0.00
Other wholesale repairs	13.48	0.00	92.41	11.09	0.38	53.79	4.93	53.51	17.17	21.53
Retail trade	8.84	0.00	35.61	16.07	1.21	87.69	56.82	54.39	19.77	29.19
Retail mechanical repairs	3.44	0.00	24.00	7.02	0.29	15.88	5.30	15.52	6.74	5.24
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	18.38	0.00	36.90	16.33	3.02	48.15	23.82	93.37	25.15	39.18
Road transport	73.46	0.00	564.22	181.37	22.43	620.55	415.74	186.63	48.57	94.16
Rail, pipeline and other transport	27.11	0.00	180.51	4.10	2.20	244.25	307.80	13.20	3.90	9.73
Water transport	2.44	0.00	25.05	5.94	1.51	44.38	220.56	31.51	4.77	8.24
Air and space transport	2.34	0.00	11.48	3.18	0.69	22.74	10.36	20.31	6.55	9.58
Services to transport, storage	30.96	0.00	131.37	56.99	3.37	282.86	148.82	217.46	139.14	130.69
Communication services	17.40	0.00	72.26	63.93	10.18	78.62	23.53	138.63	23.62	69.10
Finance	49.33	0.00	112.88	32.56	7.39	128.52	215.90	129.79	31.38	66.35
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	15.82	0.00	34.83	11.67	0.73	1530.66	476.80	191.93	60.43	101.44
Scientific research, technical and computer services	45.33	0.00	238.43	32.76	2.47	277.10	114.57	218.39	70.27	63.88
Legal, accounting, marketing and business management services	37.71	0.00	107.18	205.19	11.96	163.92	57.77	235.96	77.37	151.19
Other business services	37.22	0.00	210.38	126.04	2.25	247.53	81.02	312.32	76.43	182.20

Table B.1(f) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Glass and glass products	Ceramic products	Cement, lime and concrete slurry	Plaster and other concrete products	Other non-metallic mineral products	Iron and steel	Basic non-ferrous metal and products	Structural metal products	Sheet metal products	Fabricated metal products
Government administration	2.32	0.00	11.23	3.49	0.18	35.22	3.79	12.85	8.37	6.70
Defence	0.16	0.00	0.53	0.16	0.01	0.50	0.26	1.02	0.47	0.31
Education	5.68	0.00	26.22	9.97	0.46	34.30	16.51	24.02	4.27	7.23
Health services	0.19	0.00	0.78	0.31	0.02	0.70	0.38	0.99	0.22	0.30
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	1.31	0.00	1.22	11.85	0.58	0.94	0.01	9.12	0.29	4.99
Libraries, museums and the arts	0.32	0.00	0.43	0.47	0.00	0.00	0.00	0.00	0.00	0.00
Sport, gambling and recreational services	0.06	0.00	0.11	0.05	0.01	0.14	0.08	0.28	0.07	0.11
Personal services	0.13	0.00	0.33	0.18	0.01	0.94	0.05	0.49	0.32	0.36
Other services	0.52	0.00	2.81	3.09	0.03	2.16	1.07	8.32	2.56	3.51
Total intermediate usage including imports	**2034**	**230**	**6099**	**2622**	**356**	**15381**	**58564**	**10198**	**3063**	**5178**
Wages and salaries	609	507	1330	1254	536	3079	2786	2201	1078	2703
Gross surplus	246	238	483	157	266	2064	3315	1341	464	702
Indirect taxes on production	66	-121	194	83	32	338	945	268	114	195
Total gross output	**2954**	**853**	**8106**	**4115**	**1191**	**20862**	**65611**	**14008**	**4719**	**8777**
Value added at factor cost to output ratio	0.31	0.73	0.25	0.36	0.70	0.26	0.11	0.27	0.35	0.41
Share of wages and mixed income in value added	0.72	0.75	0.71	0.88	0.88	0.61	0.47	0.64	0.74	0.84
Employment to gross output ratio	9.47	8.14	3.93	4.97	12.42	9.00	5.46	6.20	4.50	10.59
Foreign ownership ratio	0.37	0.08	0.42	0.22	0.22	0.25	0.52	0.22	0.32	0.20
Direct tax rate on surplus	0.07	0.14	0.22	0.22	0.05	0.15	0.04	0.18	0.15	0.16
Indirect tax rate on production	0.05	0.07	0.06	0.03	0.03	0.03	0.03	0.04	0.05	0.04
Foreign income payout ratio	0.09	0.02	0.09	0.02	0.03	0.08	0.25	0.07	0.08	0.03
Replacement depreciation to value added ratio	0.27	0.19	0.23	0.14	0.11	0.14	0.32	0.07	0.10	0.08
Net national product ratio	0.63	0.79	0.67	0.84	0.87	0.77	0.43	0.86	0.83	0.89
Domestic income distribution ratio	0.16	0.20	0.13	0.08	0.09	0.25	0.23	0.24	0.16	0.12

Table B.1(g) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Motor vehicles and parts, other transport equipment	Ships and boats	Railway equipment	Aircraft	Photographic and scientific equipment	Electronic equipment	Household appliances	Other electrical equipment	Agricultural, mining, etc. machinery	Other machinery and equipment
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	0.00	0.00	0.00	0.00	0.25	0.04	0.04	0.17	0.00	0.21
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.03	1.11	0.00	6.68	0.00	0.00
Forestry and logging	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	1.88	0.06	0.01	0.04	0.21	0.35	0.08	0.09	0.07	1.17
Gas	24.14	4.36	1.41	25.75	6.21	3.26	4.51	4.91	9.62	4.83
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.54	0.02	0.00	0.01	0.05	0.10	0.01	0.02	0.02	0.03
Non-ferrous metal ores	1.51	0.05	0.24	0.02	0.62	0.29	3.10	38.76	6.98	0.99
Other mining	0.15	0.06	0.03	0.20	0.35	0.05	0.17	1.61	0.10	0.18
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	4.02	0.58	0.14	1.47	0.74	0.65	1.54	0.74	1.05	0.92
Dairy products	5.17	2.00	0.08	1.68	1.26	0.78	1.01	0.66	0.78	1.05
Fruit and vegetable products	3.65	0.88	0.28	1.68	0.55	0.59	0.76	0.58	0.69	1.58
Oils and fats	1.46	0.40	0.06	0.32	0.21	0.21	0.25	0.21	0.25	0.28
Flour mill products and cereal foods	4.18	0.66	0.16	0.89	0.68	0.72	0.84	0.71	0.84	0.92
Bakery products	3.84	0.75	0.13	0.73	0.59	0.68	0.80	0.67	0.81	1.11
Confectionery	3.65	1.05	0.12	0.82	0.48	0.52	0.60	0.51	0.60	0.66
Other food products	9.71	1.90	0.47	2.26	17.70	1.90	2.60	2.06	3.25	3.42
Soft drinks, cordials and syrups	0.71	0.10	0.03	0.17	0.13	0.11	0.12	0.11	0.12	0.14
Beer and malt	0.95	0.16	0.03	4.17	0.11	0.12	0.16	0.15	0.18	0.23
Wine, spirits and tobacco products	1.51	0.61	0.17	2.83	0.96	0.38	0.63	0.49	0.66	0.88
Textile fibres, yarns and woven fabrics	7.82	1.63	0.42	0.74	1.12	0.53	1.32	0.70	1.53	1.48
Textile products	1.76	2.37	0.41	0.73	1.45	1.47	1.44	3.16	1.57	3.13
Knitting mill products	1.78	0.47	0.07	0.35	0.34	0.27	0.34	0.27	0.32	0.35

Table B.1(g) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Motor vehicles and parts, other transport equipment	Ships and boats	Railway equipment	Aircraft	Photographic and scientific equipment	Electronic equipment	Household appliances	Other electrical equipment	Agricultural, mining, etc. machinery	Other machinery and equipment
Clothing	12.80	1.91	0.66	2.25	2.41	1.85	2.93	2.30	3.87	2.25
Footwear	1.80	0.42	0.16	0.86	0.53	0.32	0.43	0.32	0.40	0.46
Leather and leather products	3.18	0.32	0.29	0.48	1.73	0.37	0.52	0.49	0.70	0.39
Sawmill products	5.86	4.58	0.21	0.70	1.32	1.03	1.38	1.65	1.83	1.54
Other wood products	24.60	97.68	2.72	5.61	4.78	2.07	6.75	3.90	8.07	10.59
Pulp, paper and paperboard	2.41	0.81	0.28	1.08	2.13	0.74	2.16	0.76	0.55	1.67
Paper containers and products	12.95	1.51	0.50	3.04	12.77	4.21	20.71	3.78	3.86	4.82
Printing and services to printing	50.86	7.41	1.20	3.84	12.58	6.04	17.92	16.38	24.78	29.08
Publishing, recorded media, etc.	32.09	4.19	0.63	4.08	6.44	15.20	11.66	10.68	10.68	9.64
Petroleum and coal products	27.81	22.80	4.39	5.92	6.61	3.07	6.01	6.28	15.33	28.85
Basic chemicals	124.74	15.74	4.41	6.05	71.67	10.16	51.58	128.17	6.90	11.55
Paints	57.09	14.75	0.55	3.69	1.29	0.55	8.07	1.94	4.29	5.98
Medicinal and pharmaceutical products, pesticides	6.18	0.82	0.22	1.19	2.44	0.92	1.12	0.96	1.03	1.12
Soap and detergents	2.11	0.26	0.16	0.35	0.88	0.23	0.32	0.45	0.30	0.37
Cosmetics and toiletry preparations	0.40	0.08	0.02	0.11	0.06	0.05	0.10	0.06	0.07	0.08
Other chemical products	9.65	1.75	2.04	2.34	13.39	0.79	3.33	1.63	2.80	3.37
Rubber products	31.70	2.38	1.58	0.30	3.66	1.29	6.95	2.53	3.01	10.66
Plastic products	105.54	5.66	5.41	4.57	83.76	30.27	48.17	32.41	20.32	33.64
Glass and glass products	157.23	16.62	6.72	4.84	3.07	1.31	26.92	9.47	7.08	6.73
Ceramic products	2.46	0.18	0.86	0.99	0.83	0.50	1.79	1.94	2.78	1.62
Cement, lime and concrete slurry	11.86	2.05	1.18	2.50	4.50	1.26	10.13	1.39	6.24	12.87
Plaster and other concrete products	6.48	1.98	1.88	2.08	2.57	0.90	1.44	1.66	2.64	3.81
Other non-metallic mineral products	9.03	6.27	3.14	3.23	6.12	1.53	2.44	1.62	3.96	3.32
Iron and steel	948.29	292.57	84.49	14.28	158.91	35.60	586.40	158.45	731.01	881.53
Basic non-ferrous metal and products	537.71	254.17	27.41	73.46	616.39	124.15	142.68	1588.34	93.03	219.09
Structural metal products	79.40	68.70	139.13	5.66	26.86	12.54	27.47	104.41	117.13	243.02
Sheet metal products	88.41	15.79	6.97	38.12	13.27	4.83	97.24	18.68	58.35	105.25
Fabricated metal products	161.52	49.43	20.71	67.42	26.92	14.68	56.20	49.59	76.60	96.91
Motor vehicles and parts, other transport equipment	1240.96	15.20	6.98	41.18	17.34	6.47	27.51	9.68	45.91	18.04
Ships and boats	6.46	10.35	0.49	3.11	0.71	0.42	0.55	0.82	2.39	1.22
Railway equipment	13.22	0.44	322.99	0.40	0.73	0.94	3.39	2.21	1.44	3.39
Aircraft	1.59	1.70	0.03	489.32	0.05	0.05	0.06	0.07	0.39	0.06

Table B.1(g) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Motor vehicles and parts, other transport equipment	Ships and boats	Railway equipment	Aircraft	Photographic and scientific equipment	Electronic equipment	Household appliances	Other electrical equipment	Agricultural, mining, etc. machinery	Other machinery and equipment
Photographic and scientific equipment	9.98	123.04	1.22	15.01	9.09	7.43	14.52	8.85	11.72	10.24
Electronic equipment	16.57	10.64	3.46	24.05	30.63	50.23	26.67	21.99	17.50	24.86
Household appliances	28.78	9.50	1.18	2.80	3.20	2.57	95.48	5.43	8.45	6.61
Other electrical equipment	33.79	14.76	10.17	16.47	69.07	59.28	230.96	255.74	74.23	114.12
Agricultural, mining, etc. machinery	58.58	87.82	8.11	9.96	4.20	6.41	7.18	9.84	47.25	31.18
Other machinery and equipment	84.61	74.84	14.15	15.36	10.12	14.33	40.88	27.46	71.17	83.36
Prefabricated buildings	1.86	1.38	1.63	0.26	0.31	0.28	0.63	1.51	1.43	2.58
Furniture	10.42	30.87	1.22	2.29	1.61	1.94	2.58	2.89	5.19	5.37
Other manufacturing	28.78	12.29	7.04	5.85	9.58	5.36	19.14	12.26	12.24	22.09
Electricity supply	238.06	32.64	13.41	1.60	27.95	116.63	52.53	54.39	67.84	98.40
Gas supply	16.27	2.36	1.15	18.71	3.55	2.88	3.75	3.93	4.66	3.93
Water supply, sewerage and drainage services	40.68	3.17	0.92	0.00	4.26	7.85	9.31	5.34	12.15	18.66
Residential building	19.38	2.50	1.02	0.07	4.84	1.78	2.94	1.63	2.20	2.46
Other construction	26.22	3.39	1.38	0.10	6.54	2.41	3.97	2.21	2.98	3.33
Construction trade services	62.24	37.43	17.35	7.77	47.69	16.13	26.56	17.54	23.10	29.43
Wholesale trade	1976.45	321.92	77.63	422.63	335.53	352.18	407.21	392.76	411.13	448.39
Wholesale mechanical repairs	129.75	0.00	0.00	0.00	0.09	0.07	0.07	0.22	0.59	0.97
Other wholesale repairs	61.14	7.46	0.83	0.00	5.16	4.54	1.78	5.01	44.00	42.61
Retail trade	208.36	22.50	4.85	31.59	41.52	27.29	27.63	27.87	31.23	31.47
Retail mechanical repairs	13.58	3.96	0.07	0.00	1.39	1.15	1.09	3.43	9.31	15.47
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	81.73	9.50	2.63	0.00	28.36	21.44	17.06	8.30	18.18	17.31
Road transport	186.29	43.54	12.71	30.17	63.53	30.76	90.79	56.60	74.37	87.08
Rail, pipeline and other transport	18.77	1.63	0.55	4.89	4.01	1.69	4.87	2.85	13.80	28.89
Water transport	6.26	0.44	0.38	0.26	3.56	0.70	3.57	3.40	9.43	7.03
Air and space transport	33.98	6.90	0.32	0.99	13.89	10.51	18.55	14.24	30.57	25.43
Services to transport, storage	276.44	61.10	11.35	2.81	18.45	10.63	16.45	25.22	28.25	50.17
Communication services	137.83	31.82	8.41	0.00	60.22	33.99	67.30	60.93	102.34	165.98
Finance	229.53	29.86	13.91	18.11	38.92	40.23	38.08	42.80	55.57	49.08
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	1179.65	36.93	2.08	13.01	38.31	28.13	20.76	28.56	47.95	70.37
Scientific research, technical and computer services	738.74	19.33	13.09	0.00	155.22	226.63	310.89	165.78	165.05	108.54

Table B.1(g) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Motor vehicles and parts, other transport equipment	Ships and boats	Railway equipment	Aircraft	Photographic and scientific equipment	Electronic equipment	Household appliances	Other electrical equipment	Agricultural, mining, etc. machinery	Other machinery and equipment
Legal, accounting, marketing and business management services	254.06	51.78	7.33	0.00	189.08	33.45	72.99	55.18	93.65	176.05
Other business services	740.23	43.30	1.30	0.00	121.42	87.01	204.31	93.89	197.87	139.98
Government administration	57.69	6.57	0.73	0.00	4.11	1.84	4.91	3.02	6.07	4.29
Defence	0.80	0.03	0.02	0.00	0.30	0.20	0.20	0.10	0.17	0.13
Education	43.85	5.05	1.60	0.00	13.28	12.56	15.67	9.25	17.18	16.36
Health services	29.00	0.65	0.01	0.00	0.36	0.55	0.41	0.40	0.52	0.65
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	178.76	0.00	0.00	0.00	5.41	1.98	17.85	9.19	3.87	1.85
Libraries, museums and the arts	2.39	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sport, gambling and recreational services	0.24	0.03	0.01	0.00	0.09	0.06	0.05	0.02	0.05	0.05
Personal services	3.64	1.20	0.01	0.00	2.49	2.51	0.46	0.25	0.31	0.45
Other services	17.45	1.59	0.28	0.00	3.04	1.56	3.41	1.26	2.76	2.68
Total intermediate usage including imports	**14123**	**3107**	**1520**	**2799**	**3590**	**2244**	**4368**	**4814**	**4151**	**5181**
Wages and salaries	3199	1020	642	1196	1637	1614	642	1303	1748	2023
Gross surplus	2743	127	22	-31	60	296	441	649	477	589
Indirect taxes on production	532	94	45	119	104	138	110	159	153	147
Total gross output	**20597**	**4349**	**2229**	**4083**	**5390**	**4293**	**5562**	**6925**	**6529**	**7940**
Value added at factor cost to output ratio	0.31	0.29	0.32	0.31	0.33	0.48	0.21	0.30	0.36	0.35
Share of wages and mixed income in value added	0.54	0.96	1.06	1.09	1.03	0.82	0.59	0.67	0.80	0.80
Employment to gross output ratio	11.17	3.67	4.05	4.16	10.70	10.96	8.62	9.89	10.97	10.94
Foreign ownership ratio	0.50	0.40	0.50	0.50	0.30	0.20	0.18	0.13	0.80	0.42
Direct tax rate on surplus	0.07	0.75	0.75	-0.03	1.98	0.42	0.07	0.15	0.31	0.28
Indirect tax rate on production	0.06	0.05	0.04	0.07	0.03	0.06	0.05	0.05	0.04	0.03
Foreign income payout ratio	0.19	0.01	0.00	0.00	0.00	0.03	0.07	0.04	0.14	0.08
Replacement depreciation to value added ratio	0.24	0.07	0.05	0.27	0.12	0.08	0.09	0.07	0.07	0.08
Net national product ratio	0.57	0.91	0.95	0.73	0.88	0.89	0.85	0.89	0.80	0.85
Domestic income distribution ratio	0.19	0.02	0.00	0.00	0.00	0.12	0.31	0.25	0.03	0.11

Table B.1(h) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Pre-fabricated buildings	Furniture	Other manufacturing	Electricity supply	Gas supply	Water supply, sewerage and drainage services	Residential building	Other construction	Construction trade services	Wholesale trade
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.64
Grains	0.05	0.05	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.83
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.55
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.55
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.20
Other agriculture	0.17	0.53	19.27	0.88	0.00	6.51	23.93	93.58	15.49	9.17
Services to agriculture, hunting and trapping	0.00	0.25	34.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forestry and logging	0.03	19.34	0.65	1.90	0.00	0.00	1.61	56.86	6.77	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.18	0.00	0.00
Coal	0.00	0.00	0.00	3017.38	5.90	0.99	2.82	8.51	2.49	10.64
Gas	2.43	7.18	9.06	1797.48	0.00	0.00	2.76	8.63	2.43	3624.98
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.00	0.00	0.01	0.93	0.27	0.04	1.22	3.57	1.07	4.06
Non-ferrous metal ores	0.00	0.21	0.03	6.07	0.73	0.60	3.41	11.35	2.98	554.21
Other mining	0.03	0.02	6.24	0.47	0.12	12.02	107.66	336.14	159.21	1.96
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	0.10	0.56	7.73	0.93	0.11	2.55	7.36	23.41	8.19	222.65
Dairy products	0.26	1.36	1.43	2.33	0.10	10.10	12.03	21.75	6.20	55.82
Fruit and vegetable products	0.08	0.51	0.50	0.93	0.15	0.78	4.60	8.17	4.10	7.00
Oils and fats	0.03	0.21	0.20	0.72	0.10	1.23	2.96	5.12	2.04	5.53
Flour mill products and cereal foods	0.10	0.62	0.61	1.04	0.12	0.80	4.42	7.35	4.66	4.61
Bakery products	0.08	0.48	0.48	2.43	1.40	3.20	3.95	6.56	3.92	11.00
Confectionery	0.08	0.52	0.46	1.18	0.08	2.13	6.61	11.39	4.53	9.06
Other food products	1.15	2.37	5.46	3.61	0.85	3.47	26.15	41.32	16.31	32.21
Soft drinks, cordials and syrups	0.02	0.09	0.13	0.19	0.02	0.14	4.33	6.01	0.86	1.79
Beer and malt	0.02	0.12	0.12	0.20	0.02	0.36	2.63	3.77	1.69	9.00
Wine, spirits and tobacco products	0.24	0.47	1.32	0.45	0.13	3.92	5.44	7.99	3.92	20.32
Textile fibres, yarns and woven fabrics	0.12	10.11	1.78	0.75	0.31	0.96	10.50	19.36	12.88	11.86
Textile products	0.77	7.75	11.13	0.86	0.12	0.47	34.10	55.24	23.28	9.22
Knitting mill products	0.06	7.08	2.85	0.54	0.06	0.28	5.44	8.70	2.74	9.93
Clothing	0.50	3.32	2.82	3.71	0.42	1.70	10.06	18.05	9.97	18.81

Table B.1(h) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Pre-fabricated buildings	Furniture	Other manufacturing	Electricity supply	Gas supply	Water supply, sewerage and drainage services	Residential building	Other construction	Construction trade services	Wholesale trade
Footwear	0.13	0.41	1.44	3.01	0.13	0.51	2.66	7.36	2.98	5.19
Leather and leather products	0.13	5.63	51.53	0.55	0.99	0.42	3.46	7.31	4.71	6.00
Sawmill products	23.87	500.93	44.41	0.81	0.15	1.53	804.82	137.05	742.35	16.37
Other wood products	38.01	351.66	49.68	3.91	0.56	29.34	1664.80	423.85	1350.10	231.96
Pulp, paper and paperboard	0.47	6.60	4.24	1.81	0.09	0.30	35.44	55.15	10.19	34.50
Paper containers and products	0.84	6.38	5.18	12.81	1.32	5.73	126.54	198.98	33.05	244.40
Printing and services to printing	2.31	13.23	18.84	33.90	8.51	14.66	152.72	375.26	55.19	1021.94
Publishing, recorded media, etc.	1.74	6.49	8.76	13.30	2.81	11.55	56.53	116.62	23.66	469.77
Petroleum and coal products	2.16	7.18	8.13	390.97	3.70	188.32	186.34	398.33	360.74	512.03
Basic chemicals	2.73	30.44	55.10	35.94	15.30	96.86	241.00	635.34	404.98	86.63
Paints	1.84	23.84	18.84	8.53	0.93	15.20	112.63	121.71	155.04	11.54
Medicinal and pharmaceutical products, pesticides	0.49	1.71	3.10	6.10	3.36	41.43	10.87	45.50	30.44	44.04
Soap and detergents	0.08	0.90	2.20	3.19	0.98	6.01	2.65	10.35	6.32	23.04
Cosmetics and toiletry preparations	0.03	0.14	0.14	0.17	0.04	0.24	0.90	2.24	1.26	2.61
Other chemical products	1.39	15.09	7.13	4.12	1.07	3.93	82.64	215.26	169.33	28.68
Rubber products	0.23	5.93	10.52	10.85	1.22	1.40	16.05	37.38	16.07	15.23
Plastic products	3.17	68.41	163.38	11.69	29.03	44.59	686.62	910.51	528.20	221.76
Glass and glass products	6.74	34.95	7.38	2.46	0.47	3.09	122.26	143.77	75.18	264.14
Ceramic products	0.42	0.92	0.87	5.61	0.40	5.64	286.71	28.46	183.62	5.26
Cement, lime and concrete slurry	0.77	1.10	3.95	40.19	1.02	85.20	1442.16	2268.57	2051.67	10.39
Plaster and other concrete products	2.14	13.15	4.87	98.02	0.30	4.95	1247.73	776.93	1203.20	22.04
Other non-metallic mineral products	1.17	3.11	6.80	7.12	1.37	8.30	207.53	228.09	230.54	26.17
Iron and steel	104.17	168.01	274.12	30.05	13.26	44.24	837.47	2236.45	1161.22	147.99
Basic non-ferrous metal and products	83.51	249.01	598.38	20.57	6.98	24.57	636.73	492.96	278.11	63.46
Structural metal products	55.00	42.51	93.36	44.35	7.41	84.69	3027.96	3216.94	1450.53	77.75
Sheet metal products	5.96	15.01	22.42	3.73	21.00	7.43	275.29	433.92	189.19	135.96
Fabricated metal products	23.09	63.61	45.23	58.40	36.72	118.84	495.20	1184.73	479.64	123.63
Motor vehicles and parts, other transport equipment	2.80	13.78	55.27	14.92	1.46	11.82	122.76	214.53	155.03	159.31
Ships and boats	0.17	0.32	0.49	1.26	0.39	0.83	72.79	108.94	34.95	80.95
Railway equipment	0.02	0.91	0.87	2.98	0.08	0.22	5.84	9.57	4.07	4.02
Aircraft	0.01	0.03	0.24	0.48	0.02	0.11	14.87	23.23	7.02	121.36
Photographic and scientific equipment	0.24	1.44	3.68	14.80	0.35	4.32	16.23	88.40	20.88	39.01
Electronic equipment	1.42	1.93	4.70	22.15	1.06	9.75	45.82	271.54	137.05	23.66

Table B.1(h) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Pre-fabricated buildings	Furniture	Other manufacturing	Electricity supply	Gas supply	Water supply, sewerage and drainage services	Residential building	Other construction	Construction trade services	Wholesale trade
Household appliances	0.18	1.68	2.85	5.79	0.37	2.12	462.97	263.01	230.32	15.50
Other electrical equipment	1.73	5.10	12.07	399.50	1.61	13.97	170.77	1299.73	401.27	110.60
Agricultural, mining, etc. machinery	0.69	1.35	5.59	22.96	0.92	4.25	72.54	131.66	144.71	36.96
Other machinery and equipment	1.62	7.68	7.79	30.62	5.03	22.57	126.39	444.89	150.03	78.97
Prefabricated buildings	1.03	0.74	0.82	0.43	0.06	0.59	49.86	142.46	36.62	3.93
Furniture	7.00	21.66	3.91	2.42	0.39	14.88	279.97	214.42	231.97	41.11
Other manufacturing	4.20	18.39	35.76	19.02	7.90	10.00	201.35	413.32	364.40	143.34
Electricity supply	1.47	23.17	33.57	4827.31	5.92	282.16	104.04	510.88	83.52	629.05
Gas supply	1.92	5.55	7.33	585.29	0.00	0.99	28.27	6.10	10.87	241.42
Water supply, sewerage and drainage services	0.26	3.91	5.28	97.68	19.28	436.75	304.70	173.35	72.58	251.48
Residential building	0.18	0.68	1.24	160.25	82.17	62.56	1426.15	1976.41	2201.08	271.33
Other construction	0.25	0.91	1.67	230.25	111.09	86.27	2060.11	2681.58	2984.62	434.89
Construction trade services	2.31	6.96	13.39	2220.62	815.06	950.43	11408.93	13437.05	34415.77	1814.01
Wholesale trade	52.88	297.28	306.59	550.84	49.44	449.78	2181.57	3724.59	2502.70	2741.35
Wholesale mechanical repairs	0.09	0.42	0.18	67.54	31.76	36.10	101.58	216.97	59.17	58.03
Other wholesale repairs	4.90	30.34	19.14	147.54	163.60	52.18	130.66	178.25	65.25	579.01
Retail trade	4.94	44.43	94.23	70.91	12.16	39.88	243.68	626.68	275.68	1132.59
Retail mechanical repairs	6.25	24.39	29.37	234.72	47.87	61.64	178.14	502.70	895.85	983.25
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	13.53	22.77	13.07	30.94
Accommodation, cafes and restaurants	4.84	16.71	24.36	122.48	11.67	33.58	38.76	49.67	12.43	579.98
Road transport	13.32	105.45	102.28	164.16	11.44	100.55	947.47	1437.57	1065.81	1141.59
Rail, pipeline and other transport	0.78	3.03	5.29	271.92	2.07	1.07	62.45	115.20	28.30	119.07
Water transport	0.33	1.36	10.01	48.19	13.87	0.29	2.68	6.36	4.19	85.85
Air and space transport	1.47	4.65	5.44	58.93	19.46	29.85	88.59	94.80	23.54	960.80
Services to transport, storage	1.93	20.57	51.35	51.73	2.77	24.67	340.74	3216.56	388.10	9969.41
Communication services	5.48	39.23	76.67	348.59	86.62	143.56	644.46	1482.10	251.68	3116.56
Finance	9.81	43.71	38.38	1313.33	197.77	722.21	3454.88	3401.09	4318.10	3141.12
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	1.55	18.79	39.26	391.96	312.37	5.11	2745.85	6598.09	2147.70	8405.65
Scientific research, technical and computer services	8.79	25.09	17.42	248.89	51.90	28.04	253.43	6225.46	746.88	1398.42
Legal, accounting, marketing and business management services	3.99	76.50	97.04	316.29	971.67	693.63	1794.49	5040.22	2410.66	5356.98
Other business services	13.98	101.11	74.39	223.77	369.80	101.27	954.49	2917.96	1293.09	1504.10

Table B.1(h) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Pre-fabricated buildings	Furniture	Other manufacturing	Electricity supply	Gas supply	Water supply, sewerage and drainage services	Residential building	Other construction	Construction trade services	Wholesale trade
Government administration	0.43	3.28	2.62	19.07	1.65	38.65	263.71	480.88	83.84	121.97
Defence	0.01	0.07	0.07	0.09	0.00	0.00	0.67	0.73	0.14	8.58
Education	0.48	3.35	3.31	160.64	26.71	25.69	46.29	42.02	10.32	33.03
Health services	0.08	0.27	0.59	1.17	0.00	3.61	0.21	7.13	0.05	12.91
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	1.97	8.26	1.78	13.38	17.43	20.31	46.26	28.59	15.71	285.24
Libraries, museums and the arts	0.50	12.85	1.19	38.49	56.88	50.38	40.11	7.05	0.88	51.48
Sport, gambling and recreational services	0.01	0.05	0.07	0.37	0.03	0.09	227.26	349.43	126.74	158.71
Personal services	0.03	0.60	0.28	0.76	0.00	1.60	15.15	56.23	6.02	18.62
Other services	0.26	1.36	1.26	8.80	0.00	4.59	141.07	448.76	62.11	13.91
Total intermediate usage including imports	**698**	**3597**	**4012**	**20752**	**3980**	**6704**	**48434**	**83660**	**74435**	**62975**
Wages and salaries	194	1447	872	4350	182	3434	4084	13387	21745	30714
Gross surplus	136	485	49	12228	922	6065	7436	19748	17410	18696
Indirect taxes on production	20	125	75	1012	106	20	1053	1768	1902	4578
Total gross output	**1048**	**5654**	**5009**	**38342**	**5189**	**16223**	**61006**	**118564**	**115491**	**116963**
Value added at factor cost to output ratio	0.33	0.36	0.20	0.46	0.23	0.59	0.21	0.29	0.36	0.46
Share of wages and mixed income in value added	0.61	0.94	1.30	0.25	0.16	0.39	0.43	0.48	0.97	0.64
Employment to gross output ratio	7.58	24.25	12.46	2.99	8.42	4.33	4.93	7.08	14.89	7.33
Foreign ownership ratio	0.03	0.05	0.07	0.40	0.30	0.01	0.05	0.15	0.05	0.35
Direct tax rate on surplus	0.16	0.10	0.16	0.01	0.02	0.01	0.07	0.06	0.08	0.23
Indirect tax rate on production	0.03	0.04	0.02	0.04	0.05	-0.01	0.05	0.03	0.02	0.08
Foreign income payout ratio	0.01	0.00	0.00	0.27	0.23	0.01	0.03	0.07	0.00	0.10
Replacement depreciation to value added ratio	0.21	0.08	0.07	0.35	0.35	0.29	0.03	0.02	0.06	0.08
Net national product ratio	0.78	0.92	0.93	0.38	0.42	0.71	0.95	0.91	0.94	0.82
Domestic income distribution ratio	0.32	0.05	0.00	0.41	0.53	0.59	0.49	0.42	0.03	0.19

Table B.1(i) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Wholesale mechanical repairs	Other wholesale repairs	Retail trade	Retail mechanical repairs	Other retail repairs	Accommodation, cafes and restaurants	Road transport	Rail, pipeline and other transport	Water transport	Air and space transport
Sheep	0.00	0.00	502.50	0.00	0.00	181.44	0.00	0.00	0.00	0.00
Grains	0.00	0.00	0.04	0.00	0.00	0.02	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	413.05	0.00	0.00	149.45	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	3.59	0.00	0.00	1.31	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	236.53	0.00	0.00	85.58	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	310.29	0.00	0.00	134.42	0.00	0.00	0.00	0.00
Other agriculture	0.00	0.86	318.37	2.96	0.36	482.42	0.77	1.27	0.00	0.00
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forestry and logging	0.00	0.00	1.34	0.00	0.00	0.65	3.47	14.34	0.00	0.00
Commercial fishing	0.00	0.00	190.81	0.00	0.00	142.71	0.00	0.00	0.00	0.00
Coal	0.04	1.90	9.97	0.49	0.02	2.40	1.97	9.87	0.99	0.99
Gas	0.84	5.34	115.00	7.57	1.16	167.93	12.48	34.52	0.00	2.86
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.02	0.81	1.90	0.21	0.01	1.01	0.56	0.89	0.01	0.29
Non-ferrous metal ores	0.05	2.10	5.64	0.57	0.02	2.99	4.49	25.51	0.33	0.98
Other mining	0.01	0.39	0.46	0.09	0.00	3.67	0.26	0.92	0.00	0.14
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	0.38	1.56	2613.99	7.05	0.21	1837.30	3.77	1.40	0.05	1.36
Dairy products	1.54	3.07	739.73	13.59	0.92	703.01	6.83	3.32	0.12	6.46
Fruit and vegetable products	0.39	1.69	213.73	3.12	0.20	215.58	3.13	0.32	0.09	1.53
Oils and fats	0.31	0.72	134.36	2.25	0.12	82.00	1.66	0.31	0.03	0.60
Flour mill products and cereal foods	0.44	1.80	719.60	3.72	0.24	383.44	3.73	0.36	0.06	1.62
Bakery products	0.37	1.53	430.33	3.09	0.20	401.24	3.68	1.25	1.50	3.98
Confectionery	0.55	1.65	175.99	4.38	0.28	225.87	3.41	0.73	0.04	1.28
Other food products	1.17	4.30	376.52	9.25	0.60	305.00	13.24	2.35	0.22	7.69
Soft drinks, cordials and syrups	0.07	0.28	423.16	0.55	0.05	99.17	0.86	0.35	0.01	0.33
Beer and malt	0.06	0.62	4.89	1.53	0.19	1550.84	2.28	0.69	0.01	1.84
Wine, spirits and tobacco products	0.10	1.40	5.17	3.09	1.14	902.16	4.61	1.52	0.04	4.36
Textile fibres, yarns and woven fabrics	0.44	1.15	19.88	7.24	0.14	6.36	4.70	0.69	0.08	0.75
Textile products	0.06	0.84	17.71	0.76	0.20	7.75	5.40	0.96	0.13	0.23
Knitting mill products	0.16	0.72	44.33	1.79	0.13	2.02	3.16	0.63	0.03	0.62
Clothing	17.02	5.17	18.56	51.44	1.16	10.84	8.55	2.27	0.20	3.78

Table B.1(i) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Wholesale mechanical repairs	Other wholesale repairs	Retail trade	Retail mechanical repairs	Other retail repairs	Accommodation, cafes and restaurants	Road transport	Rail, pipeline and other transport	Water transport	Air and space transport
Footwear	0.16	4.97	2.76	1.50	1.35	1.62	1.76	0.30	0.03	0.80
Leather and leather products	0.60	1.17	5.20	10.14	0.29	2.08	4.16	0.69	0.29	3.37
Sawmill products	0.29	1.37	28.60	2.43	0.17	2.98	12.12	2.10	0.39	1.82
Other wood products	2.62	3.03	143.12	9.63	0.50	15.76	36.78	5.08	1.17	4.82
Pulp, paper and paperboard	0.08	0.87	21.63	1.17	0.26	24.61	13.86	3.25	1.91	16.27
Paper containers and products	1.10	6.41	192.83	6.22	2.20	93.60	10.62	10.11	1.85	19.39
Printing and services to printing	4.35	6.96	1664.05	36.44	1.56	205.04	44.97	31.26	3.66	13.65
Publishing, recorded media, etc.	3.47	6.39	820.06	28.11	1.31	103.76	22.61	36.72	3.32	12.08
Petroleum and coal products	11.11	81.63	392.69	70.68	16.25	168.35	1466.79	146.92	58.79	2002.78
Basic chemicals	3.31	8.90	49.75	20.90	1.53	56.47	16.54	11.58	0.53	8.51
Paints	4.51	8.94	5.63	19.39	1.20	4.25	1.32	1.09	0.27	0.51
Medicinal and pharmaceutical products, pesticides	0.62	2.20	23.36	5.12	0.34	10.99	5.26	2.02	0.07	2.88
Soap and detergents	0.47	1.49	11.89	2.58	0.27	25.61	4.62	1.44	0.04	0.58
Cosmetics and toiletry preparations	0.06	0.14	1.27	0.37	0.03	0.85	0.31	0.29	0.01	0.13
Other chemical products	1.37	3.91	17.17	4.09	0.82	5.19	4.32	1.38	0.27	3.29
Rubber products	1.38	6.43	4.63	15.69	0.74	4.96	20.27	0.70	0.01	0.22
Plastic products	2.48	11.20	121.51	37.34	1.35	124.50	57.90	12.38	1.88	70.53
Glass and glass products	16.56	2.32	31.70	92.26	0.28	20.45	12.81	5.64	0.02	0.47
Ceramic products	0.06	0.52	5.09	0.63	0.09	1.66	1.34	0.20	0.01	0.21
Cement, lime and concrete slurry	0.34	1.35	22.66	2.14	0.36	1.85	2.43	0.63	0.08	1.05
Plaster and other concrete products	0.33	0.90	9.80	1.59	0.10	3.96	1.36	2.90	0.08	0.51
Other non-metallic mineral products	0.16	0.54	16.12	1.20	0.07	1.74	1.05	0.55	0.02	0.19
Iron and steel	4.78	13.41	75.88	44.09	2.19	9.40	16.60	84.05	0.36	1.62
Basic non-ferrous metal and products	2.97	9.16	90.75	23.58	2.15	30.98	22.03	17.62	0.41	6.80
Structural metal products	10.34	12.96	42.54	42.59	1.01	10.74	18.20	287.25	0.55	2.37
Sheet metal products	2.44	3.40	93.18	21.33	3.15	5.46	181.07	33.52	0.91	4.19
Fabricated metal products	17.19	44.45	137.20	69.57	9.33	36.40	35.98	36.89	1.43	13.74
Motor vehicles and parts, other transport equipment	66.20	18.73	167.17	1582.32	4.39	35.59	680.59	12.00	0.51	6.40
Ships and boats	4.49	1.87	3.41	3.81	0.31	3.28	2.09	1.64	203.12	0.78
Railway equipment	1.55	2.05	4.48	4.53	0.13	1.78	6.04	1156.96	0.04	0.41
Aircraft	0.11	1.49	43.00	2.58	0.35	2.88	0.97	0.55	0.04	1368.70
Photographic and scientific equipment	3.24	27.49	16.77	13.05	2.47	12.76	8.64	4.11	0.79	17.10
Electronic equipment	4.83	101.24	11.21	15.96	5.61	18.32	13.67	4.41	0.81	15.73

Table B.1(i) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Wholesale mechanical repairs	Other wholesale repairs	Retail trade	Retail mechanical repairs	Other retail repairs	Accommodation, cafes and restaurants	Road transport	Rail, pipeline and other transport	Water transport	Air and space transport
Household appliances	4.07	41.41	28.73	17.89	108.99	43.90	16.05	8.17	0.59	12.31
Other electrical equipment	8.63	87.19	57.42	47.66	12.39	27.00	110.44	6.60	0.96	17.51
Agricultural, mining, etc. machinery	54.10	50.63	17.77	162.41	4.48	22.29	11.58	18.75	0.81	16.82
Other machinery and equipment	37.03	128.97	66.75	130.15	12.25	81.40	40.18	16.04	1.72	17.94
Prefabricated buildings	0.10	0.54	3.01	1.15	0.05	1.07	1.47	4.79	0.03	0.40
Furniture	0.89	3.27	39.80	6.32	0.39	38.34	18.10	3.57	0.12	2.86
Other manufacturing	3.69	31.46	136.75	75.26	5.92	85.95	17.01	15.98	0.42	5.53
Electricity supply	38.96	137.13	1018.69	228.00	44.40	780.66	194.40	360.15	52.31	39.47
Gas supply	0.89	3.07	115.31	7.28	1.23	147.08	6.91	12.83	2.96	2.96
Water supply, sewerage and drainage services	17.05	24.71	303.83	76.85	4.96	314.12	309.03	89.19	25.10	20.71
Residential building	10.35	69.98	123.85	21.14	1.12	78.29	46.82	40.52	1.16	14.90
Other construction	14.02	94.38	168.36	28.52	1.52	233.75	72.29	131.16	2.19	21.74
Construction trade services	144.95	185.97	598.79	119.23	16.06	793.76	112.48	781.56	5.83	30.93
Wholesale trade	210.08	913.10	1680.96	1765.04	118.91	1237.11	2245.13	167.52	42.01	1195.34
Wholesale mechanical repairs	1.06	0.00	326.59	0.00	0.00	0.50	34.92	8.08	15.45	0.00
Other wholesale repairs	0.00	0.00	715.52	0.00	0.00	26.65	125.69	32.81	51.54	77.35
Retail trade	13.15	55.31	2399.89	122.04	7.97	2584.89	330.52	43.24	3.03	383.65
Retail mechanical repairs	0.00	81.23	1145.36	0.00	13.68	37.94	3448.50	47.01	58.83	43.87
Other retail repairs	0.00	0.00	56.33	0.00	0.00	19.91	51.45	28.90	21.11	14.70
Accommodation, cafes and restaurants	1.41	9.76	345.67	22.33	4.91	54.01	160.29	15.26	6.35	39.00
Road transport	6.99	63.43	614.95	43.79	19.40	455.43	1310.11	69.91	6.06	223.35
Rail, pipeline and other transport	0.29	2.97	50.96	2.18	0.55	41.98	4.38	5.76	0.05	13.13
Water transport	0.09	3.65	35.73	0.46	0.03	4.95	4.40	0.32	136.02	0.14
Air and space transport	1.50	26.49	188.04	8.40	1.23	38.43	28.04	3.43	2.09	608.78
Services to transport, storage	17.07	28.68	819.74	89.70	7.58	309.37	657.77	55.87	779.88	1687.35
Communication services	59.06	238.08	3093.64	295.78	25.91	673.89	1010.35	54.95	16.80	136.18
Finance	88.29	224.03	2444.20	452.59	35.99	806.72	608.75	268.15	23.86	201.81
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	16.70	752.39	3732.50	209.30	3.70	1624.62	1239.53	867.32	5.98	586.77
Scientific research, technical and computer services	2.20	15.87	437.73	1.50	0.03	337.05	940.88	52.59	82.82	311.62
Legal, accounting, marketing and business management services	112.86	257.39	6658.34	694.83	54.60	1109.93	2188.96	54.30	63.35	400.34
Other business services	112.29	647.25	3867.83	82.14	1.25	582.84	263.14	83.77	10.10	148.54

Table B.1(i) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Wholesale mechanical repairs	Other wholesale repairs	Retail trade	Retail mechanical repairs	Other retail repairs	Accommodation, cafes and restaurants	Road transport	Rail, pipeline and other transport	Water transport	Air and space transport
Government administration	8.41	8.76	180.14	54.25	2.72	12.60	488.72	16.75	0.91	1.62
Defence	0.00	0.00	2.55	0.00	0.00	3.08	7.92	0.39	0.11	0.67
Education	0.95	2.43	59.27	70.61	0.69	58.23	50.30	18.41	3.38	18.39
Health services	1.02	1.74	15.74	10.36	0.75	5.72	2.52	1.25	0.75	0.21
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	1.33	1.13	1100.24	17.21	0.00	1201.12	63.12	0.82	2.77	18.34
Libraries, museums and the arts	0.00	0.00	74.09	10.96	0.00	176.12	30.36	12.70	17.21	34.47
Sport, gambling and recreational services	0.00	0.03	112.27	9.85	0.01	20.05	3.44	0.05	0.01	3.93
Personal services	0.68	0.58	54.93	4.40	0.00	21.05	0.66	1.29	0.00	0.00
Other services	0.00	0.00	21.74	5.28	0.00	6.74	18.56	0.82	0.00	0.00
Total intermediate usage including imports	**1697**	**6686**	**48333**	**9401**	**801**	**25751**	**22235**	**6070**	**2243**	**11196**
Wages and salaries	385	1445	28804	9540	1126	13483	11377	6018	461	4271
Gross surplus	264	396	18241	334	324	8547	8061	633	1177	894
Indirect taxes on production	77	360	3340	901	102	2747	2711	288	106	1573
Total gross output	**2423**	**8887**	**98718**	**20177**	**2354**	**50528**	**44384**	**13008**	**3987**	**17934**
Value added at factor cost to output ratio	0.30	0.25	0.51	0.53	0.66	0.49	0.50	0.53	0.44	0.38
Share of wages and mixed income in value added	0.60	0.75	0.68	1.05	0.85	0.62	0.72	0.88	0.29	0.66
Employment to gross output ratio	6.83	8.46	17.06	26.42	21.65	14.56	9.93	8.05	5.19	7.08
Foreign ownership ratio	0.15	0.20	0.10	0.04	0.04	0.09	0.20	0.02	0.40	0.38
Direct tax rate on surplus	0.25	0.25	0.13	0.36	0.01	0.04	0.04	0.10	0.04	0.39
Indirect tax rate on production	0.09	0.15	0.06	0.08	0.06	0.11	0.12	0.03	0.05	0.28
Foreign income payout ratio	0.05	0.04	0.03	0.00	0.01	0.03	0.05	0.00	0.26	0.06
Replacement depreciation to value added ratio	0.30	0.32	0.10	0.02	0.01	0.11	0.20	0.43	0.19	0.44
Net national product ratio	0.65	0.64	0.87	0.98	0.99	0.86	0.76	0.57	0.55	0.49
Domestic income distribution ratio	0.26	0.15	0.25	0.00	0.13	0.29	0.18	0.11	0.38	0.10

Table B.1(j) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Services to transport, storage	Commun-ication services	Finance	Ownership of dwellings	Other property services	Scientific research, technical and computer services	Legal, accounting, marketing and business management services	Other business services	Govern-ment admin-istration	Defence
Sheep	0.00	0.00	0.00	0.00	0.00	59.65	0.00	23.61	0.00	0.00
Grains	0.00	0.00	0.00	0.00	0.05	0.02	0.02	0.01	0.04	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	41.78	0.83	4.47	0.00	86.43	44.41	68.76	7.67	68.08	4.92
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.00	91.51	0.00	7.89	53.64	16.02
Forestry and logging	1.57	6.24	0.00	0.00	0.00	1.41	0.58	0.64	0.00	0.00
Commercial fishing	0.00	0.00	2.27	0.00	0.00	5.57	0.09	2.60	0.00	0.00
Coal	5.92	4.03	2.26	0.01	26.00	0.95	1.42	2.73	13.81	15.06
Gas	30.22	152.28	7.56	3.62	65.42	30.98	40.38	23.63	62.70	63.74
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	1.71	1.72	0.95	0.00	10.45	0.39	0.60	1.16	1.50	1.11
Non-ferrous metal ores	8.00	4.93	2.66	0.01	40.41	1.23	1.71	3.33	48.55	54.88
Other mining	0.82	0.83	0.45	2.86	7.81	1.27	0.48	0.67	6.06	1.47
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	3.61	20.06	9.22	1.24	18.22	41.00	34.20	18.85	3.00	10.77
Dairy products	10.03	73.75	10.59	0.38	20.61	108.77	22.56	47.58	3.26	4.28
Fruit and vegetable products	2.18	6.40	0.81	0.30	4.04	5.73	4.01	2.55	1.38	4.48
Oils and fats	1.36	5.27	0.31	0.13	2.46	7.52	4.33	2.08	1.21	1.42
Flour mill products and cereal foods	2.62	4.70	0.75	0.36	3.73	38.66	16.53	15.39	11.35	9.38
Bakery products	3.91	20.25	6.42	0.29	8.16	12.52	13.77	5.21	6.79	24.75
Confectionery	2.41	13.12	0.43	0.26	4.97	12.96	5.45	5.18	2.94	2.44
Other food products	12.08	24.25	6.05	23.29	17.05	57.84	26.92	22.19	25.12	27.46
Soft drinks, cordials and syrups	1.08	1.46	0.87	0.52	3.21	1.80	1.62	0.78	1.30	29.41
Beer and malt	3.44	2.34	3.74	0.62	3.54	3.16	1.96	1.40	5.46	3.25
Wine, spirits and tobacco products	11.14	11.12	32.94	0.80	9.49	5.58	4.03	2.70	84.13	4.39
Textile fibres, yarns and woven fabrics	2.07	12.87	0.69	1.75	4.43	4.17	1.91	1.80	4.73	5.55
Textile products	4.27	5.53	0.47	11.84	5.29	3.17	1.42	1.83	8.21	2.59
Knitting mill products	1.89	4.27	0.21	0.94	4.34	5.88	4.44	2.78	1.43	8.21

Table B.1(j) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Services to transport, storage	Commun-ication services	Finance	Ownership of dwellings	Other property services	Scientific research, technical and computer services	Legal, accounting, marketing and business management services	Other business services	Govern-ment admin-istration	Defence
Clothing	9.52	16.26	0.93	1.02	6.45	12.40	4.74	4.49	3.05	35.82
Footwear	1.51	2.64	0.19	0.30	1.64	1.37	0.87	0.66	0.63	1.94
Leather and leather products	2.03	3.48	0.46	0.57	1.35	1.85	1.90	1.50	1.03	6.63
Sawmill products	26.08	9.54	1.08	7.24	25.89	2.85	3.31	3.23	4.18	3.73
Other wood products	91.54	31.22	1.78	190.07	43.00	7.59	4.61	5.95	81.62	16.29
Pulp, paper and paperboard	3.39	93.68	26.39	1.08	9.07	13.84	37.76	8.81	122.58	4.90
Paper containers and products	7.36	33.88	3.19	0.27	9.45	16.69	10.71	5.55	57.23	6.15
Printing and services to printing	56.28	723.15	158.70	9.28	265.04	599.00	621.08	289.81	588.06	153.25
Publishing, recorded media, etc.	76.99	529.53	71.99	5.69	176.46	360.28	351.41	186.76	215.97	33.12
Petroleum and coal products	385.55	361.19	6.60	10.82	121.06	188.58	271.26	122.12	71.94	156.32
Basic chemicals	23.04	52.08	4.03	32.97	83.42	100.47	40.30	33.50	37.31	52.29
Paints	1.56	2.05	0.42	10.45	12.85	10.61	6.91	3.13	1.89	2.19
Medicinal and pharmaceutical products, pesticides	18.49	8.85	1.25	3.48	40.91	58.48	12.56	13.27	2.88	4.24
Soap and detergents	3.34	5.48	0.48	1.26	18.76	28.24	36.38	12.51	6.75	5.69
Cosmetics and toiletry preparations	0.41	0.61	0.05	0.45	1.60	0.68	0.61	0.35	0.43	0.79
Other chemical products	3.21	15.28	0.82	3.98	19.13	28.34	25.48	12.68	17.23	55.05
Rubber products	6.31	8.79	0.16	1.57	2.32	6.20	1.41	1.76	27.39	48.76
Plastic products	68.24	325.88	3.07	91.85	26.62	42.83	8.80	10.33	53.41	54.74
Glass and glass products	4.92	12.12	4.26	30.51	10.30	5.37	3.28	2.42	11.58	6.16
Ceramic products	1.49	29.17	0.24	3.14	2.52	1.66	0.76	0.82	1.18	0.78
Cement, lime and concrete slurry	2.03	9.98	1.01	56.51	8.93	12.82	2.26	6.57	4.71	3.18
Plaster and other concrete products	1.23	8.79	0.26	23.73	4.21	2.33	1.35	1.22	23.81	3.47
Other non-metallic mineral products	1.72	7.03	0.14	18.96	3.78	2.70	1.89	1.71	3.19	3.72
Iron and steel	7.91	62.75	1.73	163.75	17.20	19.18	5.76	4.50	15.89	31.22
Basic non-ferrous metal and products	20.96	80.45	7.13	141.40	62.12	24.68	20.03	15.81	41.61	41.90
Structural metal products	19.84	36.78	2.23	246.70	50.63	8.12	4.99	6.32	25.64	27.92
Sheet metal products	32.86	281.97	0.98	58.29	21.68	3.92	1.70	2.71	7.85	10.72
Fabricated metal products	19.21	86.39	5.54	67.09	56.49	56.78	17.43	15.96	50.95	117.27
Motor vehicles and parts, other transport equipment	110.92	187.51	7.04	3.82	97.83	46.03	22.23	19.25	21.43	94.20
Ships and boats	10.02	3.32	1.78	1.05	8.77	6.13	2.99	3.04	4.63	2066.14
Railway equipment	2.96	4.74	1.29	1.41	6.03	3.02	1.34	1.06	2.63	2.31
Aircraft	298.89	2.08	0.28	0.95	4.73	6.58	1.93	2.42	1.33	188.16

Table B.1(j) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Services to transport, storage	Commun-ication services	Finance	Ownership of dwellings	Other property services	Scientific research, technical and computer services	Legal, accounting, marketing and business management services	Other business services	Govern-ment admin-istration	Defence
Photographic and scientific equipment	39.36	94.93	3.29	4.12	30.34	60.23	15.50	12.36	18.83	63.41
Electronic equipment	163.18	270.11	5.80	13.46	37.22	84.53	41.60	20.35	15.25	21.59
Household appliances	17.97	20.07	1.76	33.06	19.03	10.29	5.84	4.61	3.65	20.10
Other electrical equipment	91.06	422.30	9.05	21.99	48.75	82.80	28.67	16.35	26.77	28.73
Agricultural, mining, etc. machinery	34.27	38.91	2.61	6.33	35.69	41.03	10.80	9.82	12.33	21.30
Other machinery and equipment	39.20	74.82	3.29	9.41	46.59	81.17	11.87	13.05	22.64	110.05
Prefabricated buildings	1.48	2.50	0.21	2.77	4.98	0.75	0.49	0.69	1.70	11.79
Furniture	10.25	26.68	6.43	30.05	52.66	13.63	14.06	22.13	68.50	40.41
Other manufacturing	24.93	76.65	4.11	13.35	47.34	34.47	20.52	16.07	18.07	32.94
Electricity supply	969.82	451.80	183.87	55.05	494.35	408.86	654.97	375.06	460.26	96.99
Gas supply	25.66	81.30	8.88	4.06	27.96	23.66	40.15	18.86	22.24	3.20
Water supply, sewerage and drainage services	307.59	289.88	89.89	5.36	841.35	667.32	631.30	414.66	283.62	140.94
Residential building	128.46	212.35	94.93	140.75	412.45	132.00	184.91	93.44	124.79	53.29
Other construction	269.60	293.34	127.52	261.56	606.92	181.06	271.50	127.48	273.64	185.80
Construction trade services	607.59	2469.77	68.67	1690.46	850.93	378.13	510.40	239.50	1487.62	1600.03
Wholesale trade	1057.69	2233.56	147.42	181.83	806.31	1215.16	723.43	400.91	571.25	676.30
Wholesale mechanical repairs	36.29	81.26	1.07	0.00	75.27	17.58	1.59	0.22	24.62	0.00
Other wholesale repairs	469.04	840.39	651.14	3.06	328.00	377.22	363.74	297.32	6.88	11.29
Retail trade	208.32	473.28	70.11	22.41	716.91	150.56	153.93	123.81	121.55	80.38
Retail mechanical repairs	712.44	874.32	107.38	0.00	438.44	172.40	288.21	260.05	165.44	68.79
Other retail repairs	23.48	17.85	47.78	1101.68	20.18	23.01	27.66	20.14	42.28	0.00
Accommodation, cafes and restaurants	257.45	415.68	336.40	0.00	20.04	395.60	1429.73	473.40	405.40	58.21
Road transport	467.62	543.43	98.73	53.05	164.38	250.92	294.53	100.70	389.88	144.04
Rail, pipeline and other transport	84.25	124.58	15.40	1.49	129.10	63.48	89.35	39.12	6.89	6.36
Water transport	3.64	102.98	0.15	0.16	31.88	70.46	31.49	32.87	71.57	10.57
Air and space transport	108.71	457.02	146.42	0.07	46.97	265.89	556.02	210.09	299.38	113.48
Services to transport, storage	4279.14	640.42	186.86	6.39	1440.85	546.41	1185.68	865.54	1120.62	481.32
Communication services	1584.87	1385.34	2238.48	16.59	1490.04	1651.04	2679.59	475.14	1822.75	99.93
Finance	971.83	1036.47	38388.03	6387.55	4822.26	889.67	2732.08	895.87	2538.96	287.73
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	2848.14	3954.93	2035.85	2135.99	25342.34	333.86	4208.77	2557.51	557.73	106.63
Scientific research, technical and computer services	2460.93	691.59	1258.64	28.22	2552.66	7138.12	5398.46	1272.41	2383.55	60.81

Table B.1(j) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Services to transport, storage	Commun-ication services	Finance	Ownership of dwellings	Other property services	Scientific research, technical and computer services	Legal, accounting, marketing and business management services	Other business services	Govern-ment admin-istration	Defence
Legal, accounting, marketing and business management services	1576.41	670.55	3920.44	476.39	5066.07	4302.33	4389.78	1210.08	1815.81	289.37
Other business services	1801.82	585.32	1768.95	3.39	4121.64	2299.34	3114.86	1198.50	843.49	42.06
Government administration	455.92	306.06	82.43	5.28	99.97	425.71	471.22	105.03	1494.19	46.80
Defence	19.57	5.68	6.11	0.02	3.73	9.76	8.29	4.33	14.87	0.28
Education	214.53	48.87	584.44	0.01	209.72	457.66	547.59	295.57	195.85	42.01
Health services	85.43	78.21	20.12	0.01	10.95	13.46	11.36	10.09	43.24	58.02
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	26.85	104.12	344.31	0.00	1294.89	1242.15	1737.30	565.23	113.23	85.69
Libraries, museums and the arts	25.28	43.17	136.21	0.00	119.85	161.10	353.28	88.32	45.67	12.54
Sport, gambling and recreational services	10.25	26.38	102.32	0.00	130.06	178.50	35.02	88.55	65.07	107.23
Personal services	1.05	29.19	3.16	0.06	34.73	53.01	77.10	28.21	2.96	43.93
Other services	30.81	19.58	9.14	0.00	71.63	46.61	58.14	31.34	35.04	26.62
Total intermediate usage including imports	**25567**	**27613**	**54460**	**14516**	**55612**	**31211**	**37774**	**15326**	**21317**	**11306**
Wages and salaries	9376	9636	44477	0	13749	25997	25657	23608	33990	4940
Gross surplus	15355	16546	37406	98384	27291	3241	7478	8761	1185	4547
Indirect taxes on production	1996	1466	4961	10668	2553	1410	3021	934	1170	726
Total gross output	**52294**	**55260**	**141304**	**123568**	**99205**	**61859**	**73930**	**48629**	**57663**	**21519**
Value added at factor cost to output ratio	0.51	0.50	0.61	0.88	0.44	0.50	0.49	0.68	0.63	0.47
Share of wages and mixed income in value added	0.37	0.41	0.55	0.00	0.38	1.01	0.90	0.86	0.95	0.49
Employment to gross output ratio	5.17	6.20	4.09	0.00	3.40	10.93	9.07	7.60	11.86	7.68
Foreign ownership ratio	0.10	0.10	0.20	0.00	0.10	0.15	0.05	0.15	0.00	0.00
Direct tax rate on surplus	0.02	0.12	0.39	0.00	0.09	0.22	0.23	0.09	0.00	0.00
Indirect tax rate on production	0.07	0.04	0.05	0.11	0.04	0.03	0.08	0.02	0.03	0.06
Foreign income payout ratio	0.06	0.04	0.06	0.00	0.05	0.00	0.00	0.02	0.00	0.00
Replacement depreciation to value added ratio	0.23	0.20	0.08	0.00	0.15	0.11	0.07	0.04	0.13	0.13
Net national product ratio	0.72	0.76	0.86	1.00	0.80	0.89	0.93	0.94	0.87	0.87
Domestic income distribution ratio	0.51	0.38	0.24	0.00	0.48	0.00	0.08	0.11	0.00	0.00

Table B.1(k) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Education	Health services	Community services	Motion picture, radio & television services	Libraries, museums & the arts	Sport, gambling & recreational services	Personal services	Other services	Households	Current government expenditure
Sheep	0.00	0.00	9.92	0.00	0.00	0.00	0.00	108.00	7.44	0.00
Grains	0.00	0.09	0.02	0.04	0.02	0.02	0.02	0.04	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.60	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.44	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	424.46	0.00
Other agriculture	7.71	8.28	6.60	238.60	39.74	500.36	59.22	31.39	5505.94	0.00
Services to agriculture, hunting and trapping	0.00	0.00	5.14	3.01	0.75	2.79	3.37	25.29	45.25	192.25
Forestry and logging	0.00	0.00	0.00	0.63	0.17	0.60	0.10	2.38	27.07	227.93
Commercial fishing	0.00	0.04	0.47	4.39	1.92	5.21	0.06	8.24	1098.56	178.32
Coal	1.30	2.09	0.11	1.92	0.65	2.34	0.45	1.04	16.49	1.69
Gas	54.14	87.14	15.29	9.04	4.34	12.14	7.53	31.40	532.34	4.66
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.18	0.45	0.04	0.54	0.19	0.73	0.19	0.41	0.88	0.03
Non-ferrous metal ores	0.72	1.94	0.17	1.53	0.55	2.04	0.53	1.52	2.20	0.10
Other mining	0.08	0.27	0.42	21.25	4.74	24.09	0.87	5.20	2.48	0.02
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.87
Meat and meat products	29.90	7.05	4.59	17.28	7.31	86.51	4.62	67.44	6065.47	3.11
Dairy products	116.71	17.76	17.49	6.16	3.89	26.68	2.50	156.79	5107.57	0.01
Fruit and vegetable products	7.80	7.42	1.40	2.05	2.10	5.14	1.04	5.60	2224.83	0.00
Oils and fats	6.96	5.32	1.03	1.97	1.38	4.79	4.42	2.81	719.19	11.60
Flour mill products and cereal foods	11.65	13.66	4.09	26.39	10.80	31.98	5.79	17.95	2013.20	0.01
Bakery products	56.26	20.88	12.34	4.69	2.80	8.82	0.53	8.44	2704.53	0.01
Confectionery	7.96	3.99	1.38	23.82	10.90	126.65	5.50	11.25	1949.20	0.01
Other food products	21.93	41.55	5.37	119.65	56.32	650.60	41.63	33.69	3459.07	29.57
Soft drinks, cordials and syrups	1.52	2.79	2.10	8.34	5.79	12.76	1.09	4.91	3166.43	0.01
Beer and malt	1.94	0.87	0.13	0.45	0.33	0.80	0.15	3.03	1589.55	0.01
Wine, spirits and tobacco products	13.01	1.93	0.16	1.25	0.63	1.04	0.96	5.14	2382.18	0.01
Textile fibres, yarns and woven fabrics	6.63	3.22	0.35	1.39	0.87	1.87	1.07	4.67	128.30	0.01
Textile products	10.70	11.37	0.79	1.95	0.56	7.62	1.99	7.37	741.08	0.00
Knitting mill products	3.00	110.23	5.01	2.46	0.79	2.61	0.40	4.33	445.83	0.01
Clothing	11.88	30.90	4.67	6.43	2.85	19.04	2.82	38.44	981.29	0.01

Table B.1(k) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Education	Health services	Community services	Motion picture, radio & television services	Libraries, museums & the arts	Sport, gambling & recreational services	Personal services	Other services	Households	Current government expenditure
Footwear	1.83	6.48	0.41	1.88	0.79	7.34	0.39	1.83	230.50	0.00
Leather and leather products	1.98	1.77	0.13	3.35	1.42	72.25	0.17	0.71	29.01	0.00
Sawmill products	6.71	3.44	0.24	2.45	1.67	2.67	0.62	1.44	24.72	0.06
Other wood products	162.31	9.69	1.36	48.65	27.34	18.57	3.35	7.65	156.49	0.07
Pulp, paper and paperboard	4.02	9.56	1.04	3.67	17.92	2.57	7.44	28.04	55.88	0.00
Paper containers and products	47.16	258.65	37.46	4.26	3.88	3.53	15.16	20.99	774.17	0.00
Printing and services to printing	507.29	108.59	19.69	145.34	141.13	175.77	132.09	215.34	971.34	3.63
Publishing, recorded media, etc.	1056.02	45.82	7.98	72.59	123.35	59.50	61.94	112.42	4678.66	0.08
Petroleum and coal products	7.94	169.09	11.46	23.17	9.48	39.56	26.97	179.19	6503.08	7.76
Basic chemicals	42.07	428.06	6.93	45.71	8.71	81.11	68.55	62.63	356.94	8.39
Paints	0.87	1.43	0.32	9.53	1.88	9.13	1.25	2.41	34.49	0.01
Medicinal and pharmaceutical products, pesticides	7.74	233.39	16.51	44.78	3.71	106.84	17.68	21.40	1209.88	936.84
Soap and detergents	5.67	16.71	2.20	1.76	1.10	2.01	13.90	14.63	848.87	1.66
Cosmetics and toiletry preparations	0.33	1.18	0.07	0.38	0.07	0.65	2.60	0.37	311.89	2.06
Other chemical products	4.84	8.50	2.16	3.94	1.28	4.94	5.91	27.00	231.08	2.33
Rubber products	2.63	5.27	0.40	1.27	0.36	1.93	1.48	4.65	270.56	0.45
Plastic products	40.92	64.36	3.99	13.83	8.16	14.20	32.09	37.93	785.63	0.37
Glass and glass products	14.80	24.80	1.44	5.14	3.38	5.56	1.83	8.01	386.06	0.01
Ceramic products	4.27	0.98	0.44	1.24	0.39	1.31	0.90	0.85	64.92	0.00
Cement, lime and concrete slurry	3.29	2.92	1.78	1.57	0.63	1.38	6.22	11.25	19.11	0.02
Plaster and other concrete products	6.25	2.39	0.40	2.55	1.16	1.64	3.60	6.61	12.73	0.01
Other non-metallic mineral products	2.41	2.38	0.77	1.78	0.62	1.12	10.99	7.32	17.71	0.00
Iron and steel	34.05	9.28	1.09	8.62	5.19	7.94	5.32	12.43	52.88	1.62
Basic non-ferrous metal and products	33.69	23.78	2.97	22.28	6.91	27.74	29.48	16.44	169.38	4.74
Structural metal products	172.82	6.94	0.65	26.97	24.42	25.70	4.24	6.82	71.77	0.11
Sheet metal products	17.94	20.81	1.08	5.53	2.43	6.22	2.71	3.14	95.25	0.05
Fabricated metal products	55.74	40.89	5.33	72.91	23.16	67.12	12.35	42.52	323.56	0.09
Motor vehicles and parts, other transport equipment	64.74	15.20	2.28	20.91	8.23	18.60	5.69	28.32	7152.68	1.60
Ships and boats	1.64	1.26	0.19	3.32	0.94	2.96	0.32	4.58	563.46	1.61
Railway equipment	0.95	1.67	0.08	0.48	0.21	0.67	0.18	0.63	7.63	2.54
Aircraft	2.58	0.60	0.49	6.81	0.71	4.98	0.09	8.53	25.43	1.01
Photographic and scientific equipment	134.70	639.53	1.78	7.50	2.78	18.16	3.30	24.90	1177.30	4.37
Electronic equipment	51.50	22.98	2.08	31.43	8.05	34.32	2.76	14.57	661.28	0.06

Table B.1(k) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Education	Health services	Community services	Motion picture, radio & television services	Libraries, museums & the arts	Sport, gambling & recreational services	Personal services	Other services	Households	Current government expenditure
Household appliances	9.11	23.71	2.98	31.27	10.20	45.54	1.64	6.54	2477.13	0.04
Other electrical equipment	34.40	24.94	2.69	53.58	15.84	54.09	4.51	27.46	414.90	0.09
Agricultural, mining, etc. machinery	20.20	12.43	1.58	8.41	2.80	9.27	1.72	16.01	250.42	0.07
Other machinery and equipment	33.45	27.54	2.30	15.89	5.82	21.57	6.39	31.96	303.22	0.09
Prefabricated buildings	4.34	0.85	0.07	0.71	0.76	0.78	0.27	0.95	10.27	0.01
Furniture	209.06	7.48	1.02	16.77	21.20	10.98	3.75	9.06	2358.71	0.08
Other manufacturing	75.74	50.92	5.79	37.10	14.08	31.68	10.09	36.58	820.05	0.07
Electricity supply	1299.86	389.10	62.00	181.78	57.23	216.41	104.90	281.62	10480.47	138.55
Gas supply	50.39	64.21	13.29	6.31	2.58	7.30	6.42	13.88	1180.41	38.18
Water supply, sewerage and drainage services	98.26	131.87	21.33	39.17	16.61	41.01	63.45	170.96	5128.88	1600.23
Residential building	12.41	45.81	3.93	27.59	10.09	31.52	16.18	35.71	118.03	15.17
Other construction	20.08	66.88	6.43	37.87	13.90	43.13	21.89	51.81	242.35	4735.46
Construction trade services	59.47	77.87	12.34	18.85	11.43	20.23	14.51	37.41	333.70	17.45
Wholesale trade	1196.80	1751.80	80.23	564.08	199.19	752.74	263.89	558.54	21074.07	285.60
Wholesale mechanical repairs	3.19	0.00	0.00	1.39	0.15	2.21	0.19	2.39	0.00	0.00
Other wholesale repairs	157.38	48.90	22.32	43.25	22.79	47.28	50.38	109.74	307.28	0.00
Retail trade	444.39	260.92	28.03	197.92	81.79	239.43	50.51	158.13	73095.76	3500.41
Retail mechanical repairs	60.68	243.63	14.20	90.81	42.36	147.86	25.82	137.28	6288.31	0.00
Other retail repairs	36.77	20.55	6.62	11.34	4.04	3.20	11.00	17.48	631.97	0.00
Accommodation, cafes and restaurants	173.11	18.00	19.00	171.36	58.26	172.01	45.03	125.15	36929.27	4.17
Road transport	321.95	462.56	18.62	177.54	61.09	428.09	87.28	149.39	9914.19	1350.71
Rail, pipeline and other transport	17.03	18.90	3.59	7.59	3.78	9.21	2.53	10.22	2955.80	7.74
Water transport	11.75	1.13	6.78	32.48	5.16	180.40	6.97	64.02	441.79	0.00
Air and space transport	145.94	49.68	6.33	84.65	27.62	114.93	23.64	47.94	8426.13	0.00
Services to transport, storage	259.32	180.97	12.54	100.92	42.55	111.51	16.38	97.86	1673.46	9283.50
Communication services	1219.91	1063.92	109.79	629.65	222.77	942.51	452.73	1054.68	15865.42	101.13
Finance	1061.16	1532.18	108.37	599.73	271.89	660.91	257.07	367.98	45326.34	9.78
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	123166.19	-128.08
Other property services	318.30	485.89	51.82	919.47	346.22	1373.38	205.58	408.56	1258.70	71.81
Scientific research, technical and computer services	304.76	209.12	36.87	87.95	151.01	77.98	74.36	611.89	107.10	1763.98
Legal, accounting, marketing and business management services	605.67	1676.57	76.80	768.78	262.84	1049.42	436.74	508.53	3125.06	353.37
Other business services	489.54	1258.27	122.38	529.72	296.62	881.17	462.28	846.64	1286.38	4443.75

Table B.1(k) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Education	Health services	Community services	Motion picture, radio & television services	Libraries, museums & the arts	Sport, gambling & recreational services	Personal services	Other services	Households	Current government expenditure
Government administration	284.70	114.37	13.89	18.88	20.03	16.52	65.08	17.71	1418.87	48922.65
Defence	1.90	0.51	0.20	0.54	0.97	0.49	0.64	4.94	0.00	21228.67
Education	756.21	76.87	15.69	34.67	94.49	21.92	49.31	282.61	20514.94	33273.19
Health services	49.77	480.58	4.55	25.36	2.13	39.81	3.50	34.02	23522.61	48432.90
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3004.38	13455.31
Motion picture, radio and television services	11.51	14.04	9.46	2681.19	210.13	401.62	69.93	82.99	1907.64	1520.61
Libraries, museums and the arts	606.48	24.18	14.11	215.34	165.80	165.23	0.95	82.08	979.51	3513.40
Sport, gambling and recreational services	189.45	149.63	43.52	523.26	42.74	545.92	15.65	66.45	14871.53	2093.68
Personal services	51.89	559.33	2.41	39.79	6.22	12.62	14.40	9.34	9092.39	175.64
Other services	30.67	62.82	5.10	4.14	1.84	8.49	12.86	16.86	9898.33	14550.98
Total intermediate usage including imports	**15872**	**17842**	**1362**	**11299**	**4110**	**12951**	**4039**	**9231**		
Wages and salaries	43195	47633	11048	2589	2429	4977	4570	13807		
Gross surplus	3582	6524	3721	2428	949	2780	1755	2053		
Indirect taxes on production	1321	1862	333	482	163	567	267	808		
Total gross output	**63970**	**73862**	**16464**	**16798**	**7652**	**21275**	**10630**	**25899**	**590654**	**220243**
Value added at factor cost to output ratio	0.75	0.76	0.92	0.33	0.46	0.39	0.62	0.64		
Share of wages and mixed income in value added	0.94	0.92	0.80	0.54	1.10	0.73	1.23	0.85		
Employment to gross output ratio	12.97	12.19	14.95	7.72	21.08	14.42	25.65	11.97		
Foreign ownership ratio	0.01	0.02	0.01	0.08	0.01	0.05	0.00	0.03		
Direct tax rate on surplus	0.03	0.06	0.01	0.08	0.04	0.18	0.04	0.03		
Indirect tax rate on production	0.02	0.03	0.02	0.07	0.03	0.05	0.03	0.04		
Foreign income payout ratio	0.00	0.00	0.00	0.03	0.00	0.01	0.00	0.00		
Replacement depreciation to value added ratio	0.09	0.06	0.06	0.37	0.06	0.22	0.12	0.08		
Net national product ratio	0.91	0.93	0.93	0.60	0.94	0.77	0.88	0.91		
Domestic income distribution ratio	0.06	0.07	0.19	0.37	0.00	0.22	0.00	0.13		

Table B.1(l) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Construction investment	Equipment investment	Inventories	Exports
Sheep	0.00	367.11	-8.63	1648
Grains	0.00	0.00	-64.03	5317
Beef cattle	0.00	2254.63	-37.56	490
Dairy cattle	0.00	459.16	0.55	52
Pigs	0.00	0.00	-14.40	0
Poultry	0.00	0.00	-19.61	8
Other agriculture	0.00	0.00	-25.27	1108
Services to agriculture, hunting and trapping	0.00	0.00	-48.42	415
Forestry and logging	0.00	0.00	-16.53	111
Commercial fishing	0.00	0.00	0.20	229
Coal	0.00	568.02	142.88	52158
Gas	0.00	3201.73	341.65	0
LNG	0.00	0.00	0.00	10086
Oil	0.00	0.00	0.00	8757
Iron ores	0.00	3.58	1.01	32652
Non-ferrous metal ores	0.00	131.56	-0.94	9501
Other mining	0.00	4.53	2.49	815
Services to mining	0.00	1354.05	0.00	6
Meat and meat products	0.00	46.94	58.23	5538
Dairy products	0.00	24.20	-5.49	2415
Fruit and vegetable products	0.00	37.87	28.69	995
Oils and fats	0.00	12.50	9.13	409
Flour mill products and cereal foods	0.00	42.06	5.52	1049
Bakery products	0.00	34.54	-2.99	383
Confectionery	0.00	29.83	16.29	555
Other food products	0.00	115.58	-18.45	3924
Soft drinks, cordials and syrups	0.00	9.59	-6.64	208
Beer and malt	0.00	10.96	-1.19	386
Wine, spirits and tobacco products	0.00	20.49	-0.94	2593
Textile fibres, yarns and woven fabrics	0.00	49.14	-5.38	342
Textile products	0.00	449.10	10.85	188
Knitting mill products	0.00	14.80	7.10	60
Clothing	0.00	87.42	-2.87	612
Footwear	0.00	18.90	-2.29	79
Leather and leather products	0.00	25.96	7.04	853

Table B.1(l) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Construction investment	Equipment investment	Inventories	Exports
Sawmill products	0.00	33.84	13.24	988
Other wood products	0.00	136.99	14.28	165
Pulp, paper and paperboard	0.00	10.03	23.00	575
Paper containers and products	0.00	18.60	1.81	317
Printing and services to printing	0.00	35.38	-7.12	195
Publishing, recorded media, etc.	0.00	664.14	19.64	337
Petroleum and coal products	0.00	4835.19	91.99	2642
Basic chemicals	0.00	171.26	16.52	2173
Paints	0.00	31.11	2.45	145
Medicinal and pharmaceutical products, pesticides	0.00	55.56	-1.65	2483
Soap and detergents	0.00	13.30	-0.16	264
Cosmetics and toiletry preparations	0.00	4.51	-0.27	277
Other chemical products	0.00	26.95	-4.89	477
Rubber products	0.00	44.93	1.00	256
Plastic products	0.00	495.63	2.16	716
Glass and glass products	0.00	25.24	4.32	285
Ceramic products	0.00	5.96	4.04	95
Cement, lime and concrete slurry	0.00	24.71	17.36	50
Plaster and other concrete products	0.00	31.73	45.95	59
Other non-metallic mineral products	0.00	8.86	16.48	118
Iron and steel	0.00	368.19	-26.72	4081
Basic non-ferrous metal and products	0.00	248.57	-90.04	34003
Structural metal products	0.00	323.32	60.62	278
Sheet metal products	0.00	966.17	11.80	235
Fabricated metal products	0.00	1213.54	14.21	816
Motor vehicles and parts, other transport equipment	0.00	4265.86	-18.35	3037
Ships and boats	0.00	675.16	-3.93	302
Railway equipment	0.00	431.41	-0.53	67
Aircraft	0.00	764.41	-4.96	529
Photographic and scientific equipment	0.00	775.40	1.48	1587
Electronic equipment	0.00	1053.21	-6.66	1075
Household appliances	0.00	776.38	29.04	260
Other electrical equipment	0.00	641.62	-16.43	777
Agricultural, mining, etc. machinery	0.00	3181.43	23.91	1013
Other machinery and equipment	0.00	2497.14	15.09	1612

Table B.1(l) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Construction investment	Equipment investment	Inventories	Exports
Prefabricated buildings	0.00	248.88	0.96	38
Furniture	0.00	1527.52	2.36	156
Other manufacturing	0.00	462.21	32.19	1137
Electricity supply	0.00	5618.74	3.14	65
Gas supply	0.00	872.11	176.07	2
Water supply, sewerage and drainage services	0.00	748.00	0.00	12
Residential building	51612.53	0.00	0.00	131
Other construction	99054.39	0.00	0.00	188
Construction trade services	25627.21	0.00	-0.69	398
Wholesale trade	0.00	20936.44	-31.07	14076
Wholesale mechanical repairs	0.00	0.00	0.00	0
Other wholesale repairs	0.00	0.00	0.00	1
Retail trade	0.00	2495.55	4.31	4076
Retail mechanical repairs	0.00	0.00	0.00	21
Other retail repairs	0.00	0.00	0.00	0
Accommodation, cafes and restaurants	0.00	1.36	0.00	5417
Road transport	0.00	2825.68	-17.96	7703
Rail, pipeline and other transport	0.00	109.78	-0.70	4429
Water transport	0.00	8.45	0.09	976
Air and space transport	0.00	58.65	0.00	4633
Services to transport, storage	0.00	85.99	-0.21	3365
Communication services	0.00	3980.24	0.00	816
Finance	0.00	142.67	0.00	1453
Ownership of dwellings	0.00	0.00	0.00	529
Other property services	0.00	8617.07	0.00	569
Scientific research, technical and computer services	0.00	12231.62	0.00	2652
Legal, accounting, marketing and business management services	0.00	955.75	0.00	2312
Other business services	0.00	0.00	0.00	970
Government administration	0.00	347.48	0.00	41
Defence	0.00	84.50	0.00	84
Education	0.00	64.59	0.00	4788
Health services	0.00	26.80	0.00	612
Community services	0.00	0.00	0.00	4
Motion picture, radio and television services	0.00	565.14	0.00	232

Table B.1(l) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Construction investment	Equipment investment	Inventories	Exports
Libraries, museums and the arts	0.00	85.63	0.00	162
Sport, gambling and recreational services	0.00	0.00	0.00	596
Personal services	0.00	0.00	0.00	163
Other services	0.00	0.00	0.00	48
Total intermediate usage including imports				
Wages and salaries				
Gross surplus				
Indirect taxes on production				
Total gross output	**176296**	**139197**	**587**	**269081**
Value added at factor cost to output ratio				
Share of wages and mixed income in value added				
Employment to gross output ratio				
Foreign ownership ratio				
Direct tax rate on surplus				
Indirect tax rate on production				
Foreign income payout ratio				
Replacement depreciation to value added ratio				
Net national product ratio				
Domestic income distribution ratio				

Large scale export of East Coast Australia natural gas: Unintended consequences

National Institute of Economic and Industry Research[1]

This note summarizes the major conclusions of the NIEIR study referenced here. Many major projects to export Liquefied Natural Gas from Eastern Australia have been approved and will start to operate over the next several years. This will significantly impact the domestic supply of natural gas. The National Institute of Economic and Industry Research (NIEIR) has done an assessment, reviewing the literature and conducting its own analysis of the sectoral and macroeconomic implications of these developments.

NIEIR has found that:

- If existing plans proceed, gas exports from eastern Australia will rise from 2 million tonnes (0.29 bcf/day) in 2015 to 20 million tonnes (2.9 bcf/day) in 2018, and possibly 24 million tonnes (3.44 bcf/day) in 2023;
- The current policy framework and market settings for the Australian gas industry favor export of LNG without a subsequent assurance of reliable, competitively priced supplies of gas for domestic industry. Such supplies have historically been a competitive advantage for Australian industry, and gas export revenue is insufficient to compensate Australia for the loss of this advantage;
- Natural gas is essential to a range of industries, particularly non-ferrous metals and basic chemicals, but also plastics, pharmaceuticals, paints and cosmetics. Secure local supply at competitive prices is a fundamental requirement for the continuation of a significant part of production and the development of new investment in these industries;
- Contracts for the long term supply of gas to domestic industry have ‘evaporated’ as a consequence of export commitments;
- Australia has only a few years before significant economic loss is likely to be felt from the failure to secure an affordable supply of natural gas to domestic users;
- Domestic gas users are increasingly being offered “surplus” gas volumes and prices that do not reflect domestic supply, demand or extraction costs, but are instead linked to East Asia’s LNG market – the highest-priced gas in the world. This is a radical reshaping of the domestic gas market, constraining supply (in the near term at least) and driving prices to high (and for many industries uneconomic) levels;
- Current gas production and proven reserves will need to expand dramatically in order to support the LNG expansion without significant large scale suppression of gas use on the domestic economy. While the total gas resource is thought to be very large, proving up additional resources and developing them will take time and faces community opposition and other barriers. To ensure gas availability for domestic users, the management of reserves and their supply to market needs attention if domestic needs are not to be overlooked in the rush to export this valuable resource;
- There are important opportunities to expand use of gas in industrial production and electricity generation, but even so domestic consumers cannot make use of the whole gas resource. There are worthwhile benefits to pursue from exporting gas production beyond these needs. But each cubic foot of natural gas that is shifted away from industrial use towards export, whether because of tight supply or uneconomic pricing, means giving up $255 million in lost industrial output for a $12 million gain in export output. That is, for every dollar gained $21 is lost. This increases to $24 when economy-wide impacts are taken into account;
- The dramatic shift in the domestic gas market will have wider impacts well beyond the gas intensive industries:
    - Increased operating costs for gas-fired electricity generators due to high gas prices. Such generators would see cost increases three times greater than those currently resulting from the carbon tax. Wholesale electricity prices would thus rise, and the viability of new gas-fired generation would suffer. These plants already play an important role in the electricity market for both peak power and base load. That role is expected to grow to meet emissions reduction targets and provide backup for expanding renewable generation;

[1] http://www.nieir.com.au

    - Some substitution away from gas towards electricity by business and households, to reduce their exposure to rising gas prices. This would still leave their costs higher than at present, and would raise greenhouse emissions;
    - A slow-down of general economic activity resulting from impacts of the tighter gas supply and higher costs for gas and electricity;
- The expected economic response to the East Coast LNG expansion will involve a combination of the adjustments above. As a result, modeling indicates that, by 2040 the gross production benefit for East Coast LNG expansion will be $15 billion annually, in 2009 prices. However, taking into account the negative effects of adjustment on other sectors, annual GDP will be $22 billion lower than it would be with secure and affordable gas. An alternative ‘benefit indicator’ used for this study, which combines private consumption, tax receipts and net national product, will be reduced by $46 billion;
- Under current policy settings and market structures, the unwanted consequences of the significant boom in LNG exports will persist even if, as is likely, adequate natural gas reserves exist and are brought to market; and there are substantial further risks that would lead to even greater costs if realized. These risks include:
    - LNG prices may be lower than currently expected. While this would reduce the extent of domestic price rises, it would also reduce gross export benefits while leaving domestic supply constrained in the short-to-medium term by contracted export commitments; and
    - Industry will likely be unable to grow without secure affordable gas supplies, leading to additional damage.

The likely consequences of the current policy and industry settings on natural gas export are serious for both industry and households. LNG export is a positive for Australia as long as it proceeds without significant harm to the domestic sector and with confident assurance of domestic supply.

Reference

National Institute of Economic and Industry Research, “Large scale export of East Coast Australia natural gas: Unintended consequences.” A report to the Australian Industry Group and the Plastics and Chemicals Industries Association, October 2012.

Mining the Data: Analyzing the Economic Implications of Mining for Nonmetropolitan Regions

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Extractive industries such as logging and mining are generally expected to bring significant economic benefits to rural regions, but a growing number of findings have now challenged that common expectation. Still, it is not clear whether the findings of less-than-desirable economic outcomes are isolated or representative. In this article, we assemble literally all of the relevant quantitative findings on mining that we have been able to identify in published and/or technical literature from the United States. In the interest of rigor, we limit the assessment to cases in which strictly nonmetropolitan mining regions are compared against other nonmetropolitan regions and/or against those regions' own experiences over time. Overall, 301 findings meet the criteria for inclusion. Contrary to the long-established assumptions, but consistent with more recent critiques, roughly half of all published findings indicate negative economic outcomes in mining communities, with the remaining findings being split roughly evenly between favorable and neutral/indeterminate ones. Positive findings are more likely to be associated with incomes than with poverty or (especially) unemployment rates, and they are more likely to come from the western United States, where much of the mining involves relatively large, new coal strip mines. Over half of all positive findings come from the years prior to 1982. In virtually all other categories, the plurality or majority of findings have been negative. When the patterns of findings are subjected to one-sample means tests, the only way to produce a significantly positive outcome is by combining all neutral/indeterminate findings with the positive ones, while focusing exclusively on incomes; by contrast, in the case of poverty or unemployment rates—as well as for the overall body of findings—the results are consistently and significantly negative, whether the neutral/indeterminate findings are combined with negative ones or omitted from the equations altogether. Until or unless future studies produce dramatically different findings, there appears to be no scientific basis for accepting the widespread, "obvious" assumption that mining will lead to economic improvement.

Both in academic and popular discourse, the common assumption has long been that the potential environmental threats from extractive industries such as logging and mining will be accompanied by economic benefits for the industries' host regions (see, e.g., Imrie 1992; Thompson and Blevins 1983, p. 153; cf. Humphrey et al.1993; see also Lewan 1993). Indeed, particularly for areas that are remote from urban agglomerations and industrial development, the extraction of raw materials from nature is often seen to be the only hope for economic

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development. At least in principle, it would seem reasonable to expect a rich natural resource endowment to translate into increased prosperity, because resource-dependent industries have significantly less locational flexibility than do most other industrial activities. New mines, for example, can only have a realistic opportunity to be profitable in locations where actual mineral deposits are available. In recent years, however, the common assumptions have begun to be undercut by a growing body of findings.

To date, it is not clear whether the findings of less-than-desirable socio-economic outcomes are idiosyncratic or systematic. In this article, accordingly, we seek to provide a comprehensive summary and assessment of the accumulated findings, focusing on mining-dependent communities. We begin with a qualitative review of the existing literature, including known technical reports and other "gray" literature as well as the findings published in peer-reviewed journals. We follow with a quantitative analysis of the key categories of available socioeconomic findings—those on income, unemployment, and poverty rates—that permit "apples to apples" comparisons of the experiences of nonmetropolitan mining regions against those of nonmetropolitan comparison regions and/or against their own experiences over time. The closing section considers this study's implications for future research on natural resource development in nonmetropolitan regions.

Overview of the Literature

Over the past several decades, researchers have begun to question the once-common assumption that mining would bring socioeconomic prosperity to host regions. The questioning appears to have begun outside of the United States, when authors such as Frank (1966, 1967) began to draw attention to "underdevelopment," which was argued to be due in part to unfavorable terms of trade—with raw materials being sent out from extractive regions at relatively low prices, in unequal exchange for finished products that needed to be imported at high prices. In subsequent years, other international studies (see, e.g., Barham and Coomes 1993; Bunker 1985; Repetto 1995; Schurman 1993) have indicated further reasons for concern. Indeed, careful quantitative analyses have found that—even after controlling statistically for other variables, ranging from the openness of a national economy, to the efficiency of national bureaucracy, to the degree of inequality in national income concentration—nations with high rates of natural resource exports have had abnormally low rates of subsequent economic growth (see, e.g., Sachs and Warner 1995; for a careful review of the larger literature on this "resource curse," see especially Ross 1999).

The work of Corden and Neary (1983) helped to draw increased attention to the paradoxical implications of extractive industries in industrialized countries, highlighting what the authors called "Dutch disease": Holland's massive North Sea oil revenues were actually found to be associated with declining rather than improving economic fortunes. At least initially, however, such findings received relatively little attention in U.S. community studies. As many rural community leaders have been quick to point out, after all, jobs in logging and mining tend to pay far higher wages than do service jobs such as cleaning hotel rooms or serving fast-food hamburgers. This point is not simply a widespread belief with no empirical support; instead, the nationwide study by Mills (1995), for example, found that earnings per worker were higher in mining than in many other economic sectors—whether considering metropolitan or nonmetropolitan regions, and whether focusing on the "mining boom time" of 1980 or on the nonboom years of 1970 and 1990. In important respects, accordingly, it has long seemed "obvious" to many commentators that extractive industries should be associated with significantly increased local prosperity. In addition, while examinations of the economic characteristics of mining communities have had a long history in the social sciences (for a review, see Field and Burch 1991), few studies seriously questioned the common assumptions and expectations until the 1980s.

Moreover, in one of the first studies to look at the topic in a broad-brush fashion, Bender et al. (1985) obtained results that were reasonably consistent with the usual expectations. Drawing data largely from the 1980 Census of Population and Housing and using a definition that would later be followed by many other authors—with "mining-dependent" counties being those where 20 percent or more of total labor and proprietor income came from mining—Bender et al. found that mining-dependent counties had higher population growth rates, higher incomes, and fewer people receiving social security than the nonmetropolitan average of the times. The study did note, however, that "the variations among counties . . . were large," and that decreases in demand for fuels and minerals between 1979 and the time of their study in 1985 had "produced income and population declines" that did not show up in their study's quantitative analyses (Bender et al. 1985, p. 9).

The subsequent trends were soon to be documented more systematically. Hady and Ross (1990), both of whom were coauthors on the original Bender et al. study, conducted an update, examining the differences between counties that were mining-dependent by the same definition in 1979 (during the height of the energy crisis and mineral prices) and in 1986 (after both a recession and a drop in mineral prices). In the 7 years between 1979 and 1986, mining employment in the nonmetropolitan United States declined by 14 percent; 50 counties ceased being mining-dependent, while only 19 others became mining-dependent during that period. On average, whether focusing on the counties that were mining-dependent in 1979, 1986, or both, the follow-up study found declining personal incomes and increasing unemployment from 1979 to 1986.

Other researchers soon found evidence that less-than-favorable findings were not limited to a 7-year period. In a more comprehensive review of natural-resource-oriented industries, for example, Weber, Castle, and Shriver (1987) found that, while counties with energy-related mining experienced growth in both employment and earnings during the generally "booming" years of 1969–1985, counties with metal mining experienced declines in both indicators, even during those years.

These kinds of results have raised questions about the degree to which the findings from Bender et al. (1985) may have been influenced by the extraordinary conditions in energy extraction that happened to be approaching their peak around the time period considered in that initial study. One of the points that has become quite clear, for example, is that the areas of the United States having the highest levels of long-term poverty, outside of those having a history of racial inequalities, tend to be found in the very places that were once the site of thriving extractive industries—most notably in Appalachia (Gaventa 1980), but to a lesser extent also in other one-time mining and logging areas such as the "cutover region" of the Upper Midwest (see, e.g., Landis 1938; Lisheron 1991; cf. Schwarzweller and Lean 1993). Perhaps more ominously, the reasons for concern are not limited simply to the implications of ultimate shutdowns or "busts." Several studies have found evidence of problems even while extraction is occurring (e.g., Cook 1995; Drielsma 1984; Elo and Beale 1985; Freudenburg and Gramling 1994; Krannich and Luloff 1991; Peluso et al. 1994; Tickamyer and Tickamyer 1988).

In subsequent years, a number of studies have compared census data from different regions and times. Perhaps the most systematic of these analyses can be found in the work of Nord and Luloff (1993), who offered three kinds of comparisons—comparing data from the 1980 and 1990 censuses, from three regions of the country (the west, the south, and the Great Lakes), and from three different sectors of the mining industry (coal, petroleum, and "other," the last of which includes metal mining and quarrying). These authors' analyses mirrored the findings of Bender et al. in showing that conditions were relatively favorable at the time of the 1980 census, but further analyses showed that the economic implications of mining in all three regions of the country, and in all sectors of the mining industry, had deteriorated since that time. Except in the western region, in fact, unemployment was found to be consistently higher in mining counties than in other nonmetropolitan counties, in each respective region of the country, both in 1980 and in 1990. By 1990, in all but the western region, mining-dependent counties had lower incomes and more persons in poverty than did the nonmining counties. In all regions of the country, including the west, mining-dependent counties experienced greater increases in poverty rates from 1980 to 1990 than did other nonmetropolitan counties. All in all, the only favorable findings associated with mining areas in the 1990 census were found in the western United States—and even there, the findings provided less reason for optimism than had appeared to be the case in 1980.

Other studies have found that local residents' widespread expectations for improved employment may be particularly problematic. In analyzing a decade's worth of data compiled by Weber et al. (1987), for example—a period that included both the "boom years" of extractive industries in the late 1970s and the "agricultural crisis" years of the early 1980s—Krannich and Luloff (1991) found that mining-dependent counties had higher levels of unemployment than did agriculture-dependent counties, in every single year, even during this period. In addition, there is at least suggestive evidence that mining communities' economic problems tend to become increasingly pronounced over time, exacerbated by the volatility of commodity prices, the potential for a cost–price squeeze, and the problem of "flickering" (i.e., the periodic shutting down of extractive operations, as prices fluctuate above and below the costs of operation in specific locations—see Hibbard and Elias 1993). This flickering can contribute to problems of unemployment and poverty, given that laid-off workers will often choose to remain in the area, sometimes for extended periods, in the hope or belief that the high-wage jobs will ultimately return (see, e.g., Freudenburg 1992; Krannich and Luloff 1991).

Perhaps in part because of findings such as the ones being summarized here, there is a potentially telling contrast in two types of studies that have gauged the reactions of local leaders. In regions that are expecting increased mining or just beginning to experience a "boom," it is common to find what Gulliford (1989) calls "euphoria." Unfortunately, in regions that have actually experienced natural resource extraction, local leaders have been found to view their economic prospects less in terms of jubilation than of desperation (e.g., Krannich and Luloff 1991; Freudenburg 1992; Gulliford 1989; Peluso et al. 1994; cf. Cottrell 1951, 1955; Gaventa 1980). Thus, while the largest of the nine working groups established by the Rural Sociological Society's Task Force on Rural Poverty was the one that focused on natural resources, the working group ultimately identified resource extraction not as an antidote to poverty, but as something more like a cause or correlate. In the authors' terminology, they found resource extraction to have a "systematic relationship" with "the impoverization of rural people"—so much so that the bulk of their review was devoted to an effort to identify "social forces at work in resource-dependent rural communities that lead to the creation of relative and/or absolute poverty" (Humphrey et al. 1993, pp. 137–8; see also the responses to this report, including Freudenburg and Gramling 1994; Peluso et al. 1994; Nord and Luloff 1993).

Quantitative Analysis of Available Findings

While even a qualitative literature review can illustrate the need for caution, there is clearly also a need for a more systematic assessment of the relevant evidence. Mining would appear to deserve particularly close attention in that, to repeat, jobs in mining tend to be associated with some of the highest incomes in any economic sector (Mills 1995). In response, we have sought to bring together and analyze the available findings in a way that would be more systematic, and yet that could be reported in a manner that is as straightforward as possible.

As suggested by the foregoing review, there are many differences across the available studies—a fact with a number of important implications. First and most clearly, differences in the units of analysis and the operationalization of variables mean that any comparisons need to be interpreted with caution—as being indicative of overall patterns, rather than as providing definitive or clearcut answers. Second, the available findings are not independent; instead, there are multiple overlaps but also differences across studies. In terms of overlaps, for example, many authors use statistics from the Census and/or the Bureau of Labor Statistics, but at the same time, there are many differences in the time periods and specific sets of counties being considered. In terms of differences, some authors distinguish carefully between "community-level" versus "county-level" data, while others use the terms more or less interchangeably, and some authors focus on officially "rural" communities (those with fewer than 2,500 residents), while many other studies include nonmetropolitan regions more broadly.

Such overlaps and differences would make it inappropriate and potentially misleading to perform extensive statistical transformations or analyses; instead, the more responsible approach is to assess the findings in terms of simple and easy-to-understand categories. In the analyses that follow, accordingly, we have classified the results in terms of a three-way typology—as indicating, in other words, conditions that are more favorable, less favorable, or no different from the conditions prevailing in relevant nonmining areas and/or during earlier time periods. In the effort to avoid the imposition of our own views, we have deferred to the original authors' interpretations of the data whenever such interpretations are available. A "favorable" finding, for example, thus usually reflects the judgement of those who wrote the report or article in question, whether the judgement was based on statistical analyses or on simple comparisons of descriptive data.

It is also important to recognize that the available literature poses still other challenges for an effort that is intended to be both careful and conservative. In particular, while the overall body of literature addressing the economic well-being of mining-dependent areas is vast, the number of studies explicitly offering systematic, quantitative data on the impacts of mining in the rural United States is actually much smaller. In the process of selecting the findings for analysis, accordingly, we needed to proceed in two main steps. The first step was to conduct an extensive search of articles published in peer-reviewed journals, books and chapters, technical reports, and governmental documents and publications. Because of this process, we ultimately identified several hundred reports and publications in all. In the second step, however, we found it necessary to deal with the potentially misleading variations across studies by requiring an appropriate degree of consistency in the studies that were selected for more detailed examination. This process ultimately led to the identification of four relatively stringent criteria that were necessary to permit direct and meaningful comparisons and to the elimination of all studies that were unable to meet the criteria.

The first criterion was the most straightforward. The studies needed to present enough comparative data—whether across locations, across time, or both—to permit a reasonable assessment of net economic impacts for the areas affected. Second, the studies needed to provide quantitative assessments of the impacts of mining activity in nonmetropolitan communities or regions in the United States. This criterion alone was enough to eliminate roughly half of the otherwise "available" studies (e.g., those from other nations), and even in the remaining studies, there were a number of variations in the definitions of "mining" and mining dependency. Most studies have used broad definitions, encompassing the full range of metal, coal, and oil-extraction activities, as well as quarrying, while a smaller number have focused on one type of mineral. Nearly half of the studies defined "mining dependency" according to the criterion used by Bender et al. (1985), including only those counties that received at least 20 percent of their total labor and proprietor income from mining during the period specified. The remaining studies followed one or more mining areas over time, required that a given percentage of local employment be from mining, or relied on measures involving a mixture of income and employment from mining.

The third criterion also requires additional discussion: For purposes of comparability, the data in question needed to present at least one of the three variables most commonly included in such studies—namely, incomes, unemployment rates, and poverty rates—corresponding closely to the three kinds of local economic benefits that are commonly expected to be associated with mining. Even among the studies meeting this criterion, however, there proved to be a number of variations, particularly in the definitions of "poverty" and "income." In the comparisons that follow, accordingly, the "poverty" category will include all findings regarding the percentage of persons in poverty, the percentage of children in poverty, and the percentage of families in poverty, while the "income" category includes studies that provide data on median household income, per capita income, and/or wage and salary earnings. The measures of "unemployment," by contrast, involve fewer variations, usually referring to the percentage of the workforce unemployed at the time of data collection, although a few studies use analyses of unemployment insurance payments.

The fourth and final criterion proved to be particularly conservative. Even after the application of the first three criteria, there were still 363 known, quantitative findings in the available literature. The fourth criterion, however, required the exclusion of all areas that were merely “predominantly” rural or nonmetropolitan, although many people think of predominantly rural states, such as North Dakota, or cultural regions, such as upstate New York or Appalachia, as being “rural.” The reason was straightforward: Given that metropolitan areas tend to have significantly stronger economic conditions than do nonmetropolitan areas, important biases might be created by comparing (genuinely) nonmetropolitan mining regions against “control” regions that actually included one or more metropolitan areas (e.g., by comparing the nonmetropolitan mining counties in a given location against the average for the entire region, or for the United States as a whole). The net effect of this fourth criterion was to lower by 51 the number of “adverse” findings on the economic implications of mining, while lowering “positive” findings by only 11. Still, even after the application of this fourth and final criterion, there remained 301 of the “more conservative,” quantitative findings, derived from 19 separate studies.

As indicated by Figure 1A, by far the most common findings in the literature are those involving adverse economic outcomes in mining regions. The dashed-line totals indicate that adverse findings constitute an outright majority of the “known” findings (those meeting all but the fourth criterion). Even after the imposition of the fourth and most conservative criterion, just under half of the findings that remain—139 of the remaining 301 findings, in other words, or 46.1 percent of them—indicate the economic conditions in mining regions to be worse than those in the relevant comparison regions. The remaining findings are split roughly evenly between neutral and favorable outcomes, at 74 (24.6%) and 88 (29.2%), respectively. For purposes of clarity, Figure 1B includes only the “more conservative” 301 findings, and in the remainder of this article as well, we will analyze only the 301 findings that meet all four criteria for inclusion. What Figures 1A and 1B show, at least at an overall level, is that favorable or improving economic conditions need to be recognized as being considerably less common in the empirical literature to date than are unfavorable or declining conditions.

Still, to leave the matter there might be too simple. As could be expected on the basis of the preceding literature review, there are a number of variations in the relationships between mining and economic well-being. While the variations among available studies suggest that more detailed analyses should be undertaken only with caution, as noted earlier, there are three types of additional comparisons that are particularly worthy of attention. First are those that focus on the differences that emerge from examining specific indicators of socioeconomic conditions (i.e., incomes, unemployment, and/or poverty rates); second are those that deal with regional variations; and third are those that offer insights into change over time. We will discuss the three in that order. In the interest of conservatism, all of the more detailed comparisons that follow will use only the

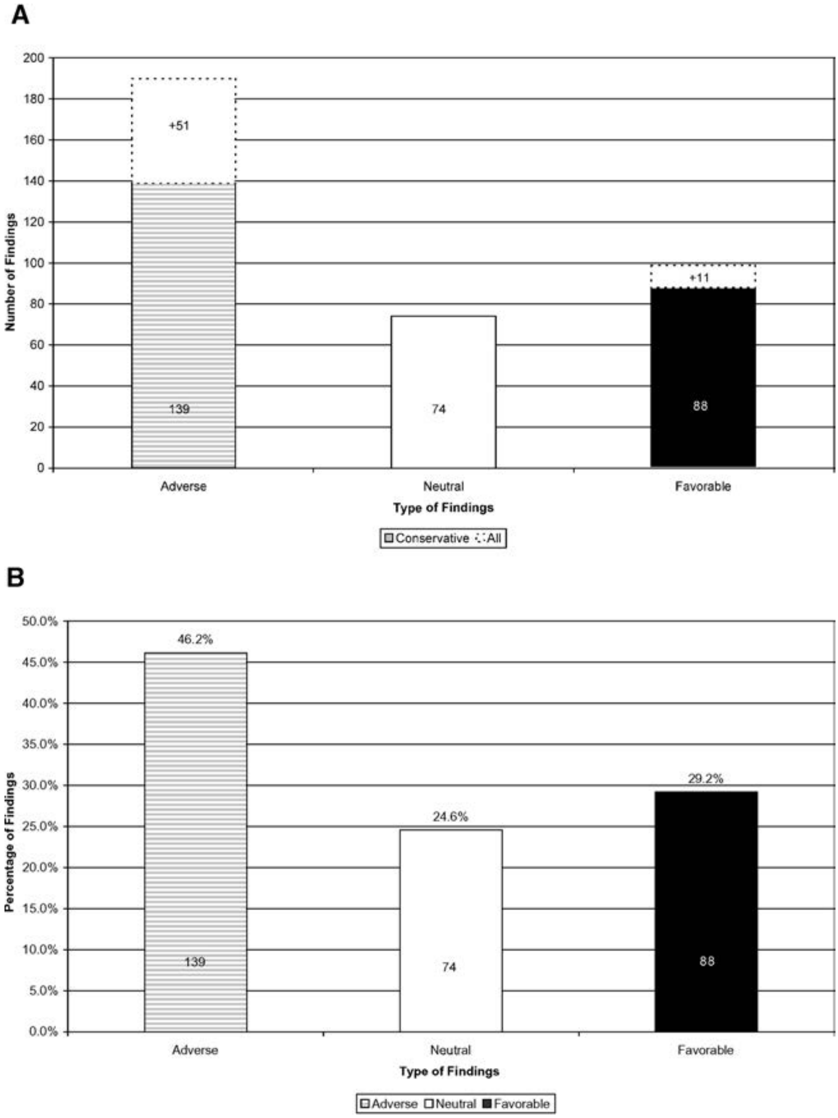

Figure 1
(A) All findings versus "conservative findings." (B) Summary of findings (used in final analysis).

301 findings that meet all four of the criteria for inclusion, and tests of statistical significance will be presented only for the overall totals and for the comparisons involving overall socioeconomic measures or indicators.

Differences across Indicators

The first set of more detailed comparisons involve differences across the three different socioeconomic indicators noted above—income, unemployment rates, and poverty rates. Of the three indicators, the most positive picture emerges from studying incomes, as illustrated in Figure 2. The available studies provide 118 quantitative findings on income differences; in 56 of these cases, or nearly half of the time, mining activity has been associated with higher incomes than in nonmining areas or in previous time periods. Incomes are lower in about one-third of the findings (40, or 33.9%) while the remaining 22 findings (18.6%) indicate a situation that is "no different." Thus, while it may not be literally accurate to describe mining as leading to improved incomes, more findings do fall into the "favorable" category than into the other two, suggesting that mining has indeed been associated with higher income levels in many cases.

A less favorable picture emerges, however, when we consider the fuller range of economic findings. Despite the fact that impoverished rural communities often expect mining to reduce their poverty rates, for example, the findings fail to

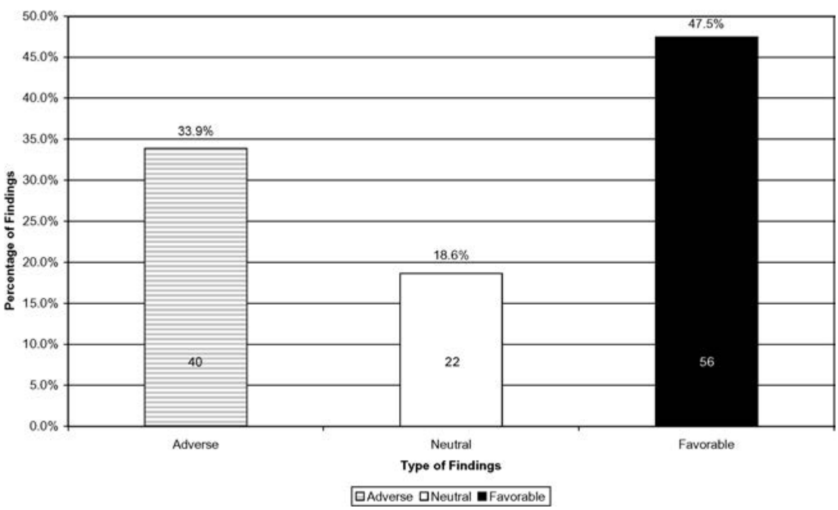

Figure 2
Summary of income findings.

support this common assumption. As can be seen from Figure 3, only about 20 percent of the 59 available findings on the topic indicate mining areas to be associated with lower poverty rates. Instead, more than twice as many findings—26 findings, or 44.1 percent—indicate higher levels of poverty in mining areas, while the remaining 21 findings (35.6%) indicate poverty levels that are neither higher nor lower than in the relevant comparison areas. Likewise, despite the usual assumption that mining will reduce the unemployment problems of rural areas, studies to date have actually tended to find higher levels of unemployment in mining areas than elsewhere. As can be seen from Figure 4, which summarizes the available findings on unemployment rates, a clear majority of the available findings (73 of the 124 findings, or 58.9%) indicate higher levels of unemployment in areas characterized by high levels of mining activity, while another 25 percent of the findings (31) point to conditions that do not differ between mining and comparison areas. Despite the widespread expectation that mining will lower local unemployment rates, actual findings of such favorable conditions prove to be relatively rare, making up the smallest category of all, with just 20 findings (16.1%) suggesting unemployment rates to be lower in mining areas than in comparison areas.

In addition to the graphic presentation of evidence in Figures 1–4, we have provided a quantitative summary and a set of significance tests in Table 1. The

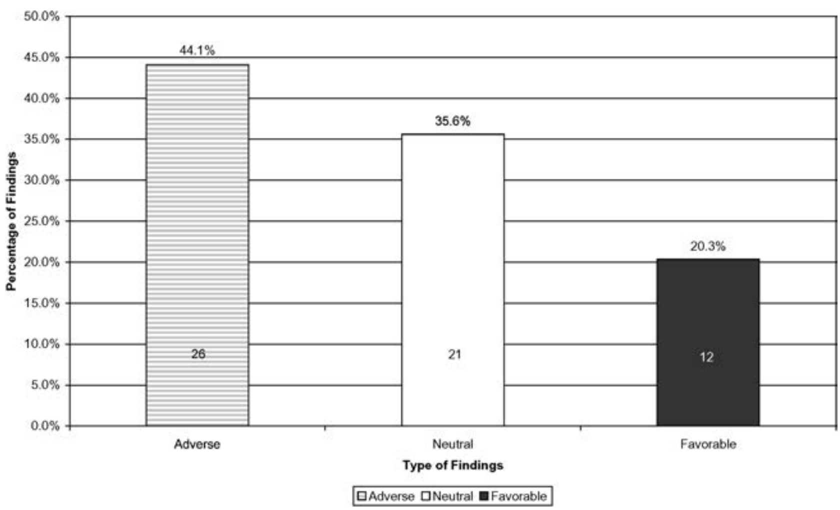

Figure 3
Summary of poverty findings.

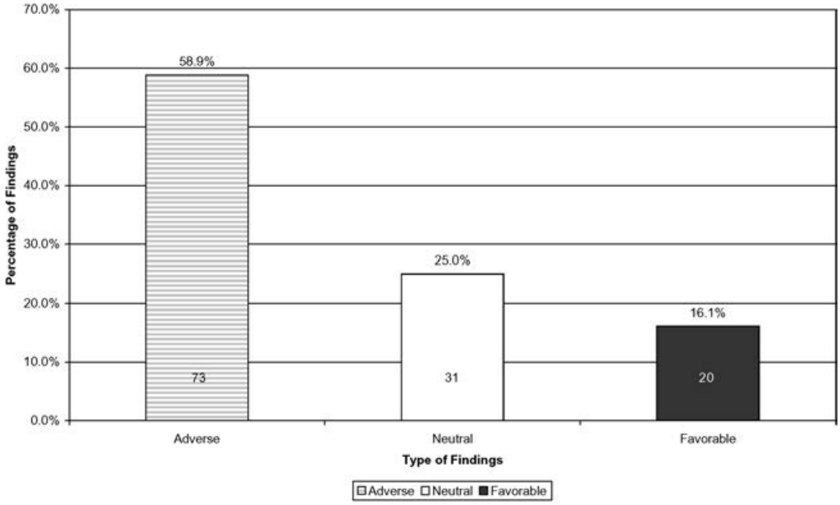

Figure 4
Summary of unemployment findings.

top three lines of the table focus on the overall findings from Figure 1; for the convenience of those who prefer a more detailed examination, the remaining lines of the table summarize the findings in more specific ways. The first column reports the raw number of findings of each type. The second column expresses this number as a percentage of the findings within a given category—that is, as a proportion of all the relevant findings on income, poverty, and unemployment rates—thus repeating the information from Figures 1–4 in tabular form. The final column of the table provides new information, expressing each subcategory of findings (e.g., adverse findings on income, or favorable findings on unemployment rates) as a percentage of the grand or overall total of 301 findings that meet all four of the criteria for inclusion in this analysis.

For each panel of the table, we also present the result of statistical significance tests. Before we turn to the tests themselves, however, four warnings are in order. First, as statistical textbooks routinely note, tests of "statistical significance" should not necessarily be taken as indicating "substantive significance." The tests, instead, are meant to assess the relative consistency of (and hence the degree of statistical confidence that can be placed in) any given pattern. Second, because we are looking at findings from the existing research literature on the three main categories of findings (i.e., incomes, poverty, and unemployment rates), the statistical tests reported here can only be generalized to the research literature addressing these comparative, quantitative results from mining-dependent, nonmetropolitan regions of the United States. Third, given our earlier warning that outcomes reported in the existing literature are often not independent of one another, an important degree of caution is needed in drawing even these inferences; the major advantages of the significance tests have to do with clarifying and systematizing the available findings. Fourth and finally, in keeping with our earlier warning about the need for caution in interpreting the relatively small number of some of the more specific findings, we will perform the statistical tests only for the largest categories of findings, namely, those already noted—the results on incomes, poverty and unemployment rates, and overall patterns.

The simplest possible approach for testing the statistical significance of these findings is to focus on what are technically known as "binomial" outcomes—that is, those that allow for just two possible outcomes. In accordance with the need for caution, the "cost" of this simplicity is that the tests can be carried out in three different ways—with the neutral findings being combined with positive ones, with negative ones, or being omitted altogether.

In Table 1, we present information on statistical significance only for those comparisons that produced significant results. For the overall findings that are summarized in the top panel of Table 1, for example, the binomial tests show adverse findings to be significantly more common than favorable findings according to two of the three possible comparisons—those where the neutral findings are combined with the adverse findings or where they are omitted from the analysis—although not when the neutral findings are combined with positive ones. For the most favorable of the available sets of findings, by contrast—those for incomes—the only way to obtain significantly more favorable findings than negative ones, according to normal standards of statistical significance, is to treat all of the neutral or indeterminate findings as being "favorable" ones, as well. Finally, unlike the case for the income findings, there prove to be significantly more adverse findings than favorable ones in the cases of poverty and unemployment, whether the neutral findings are treated as being negative or are removed from the analysis altogether. In the case of the unemployment findings, in fact, adverse findings prove to be so much more numerous than positive ones that there are significantly more negative than positive findings even if the neutral or indeterminate findings are explicitly treated as positive ones.

In response to reviewer concerns about the extent to which this overall pattern might be shaped by methodological anomalies of one or more studies—whether through shifts in units of analysis or definition of variables, or simply by having one or two studies that contribute a significant fraction of the findings—we have conducted the additional analysis summarized in Figure 5. As can be seen from the dashed horizontal line and the bar at the far right end of this figure, the overall average, across all studies, is for negative findings to be 1.58 times as

Table 1
Percentages of Adverse/Neutral/Favorable Findings, Overall and by Measure

	No. of Findings	% of Category	% of Total
Overall			
Type of Finding			
Adverse	139	NA	46.2
Neutral	74	NA	24.6
Favorable	88	NA	29.2
Total All Findings	301	NA	
"Adverse Findings" are significantly more likely than "Favorable Findings" by two of three tests:			
$t = -7.907$, $p < .000$ when neutral findings are coded as negative.			
$t = -3.466$, $p = .001$ when neutral findings are excluded.			
By Measure			
Income Findings			
Adverse	40	33.9	13.3
Neutral	22	18.6	7.3
Favorable	56	47.5	18.6
Total Income	118	100.0	39.2
"Favorable Findings" are significantly more likely than "Adverse Findings" by one of three tests:			
$t = 3.679$, $p < .000$ when neutral findings are coded as positive.			
Poverty Findings			
Adverse	26	44.1	8.6
Neutral	21	35.6	7.0
Favorable	12	20.3	4.0
Total Poverty	59	100.0	19.6

(continued)

Table 1 *(continued)*

	No. of Findings	% of Category	% of Total
"Adverse Findings" are significantly more likely than "Favorable Findings" by two of three tests:			
$t = -5.612$, $p < .000$ when neutral findings are coded as negative.			
$t = -2.411$, $p = .021$ when neutral findings are excluded.			
Unemployment Findings			
Adverse	73	58.9	24.3
Neutral	31	25.0	10.3
Favorable	20	16.1	6.6
Total Unemployment	124	100.0	41.2
"Adverse Findings" are significantly more likely than "Favorable Findings" by all three tests:			
$t = -1.999$, $p = .048$ when neutral findings are coded as positive.			
$t = -6.652$, $p < .000$ when neutral findings are excluded.			
$t = -10.213$, $p < .000$ when neutral findings are coded as negative.			
Total across Measures	301	NA	100.0

common as positive ones. As can also be seen, however, there are very few cases in which the removal of a study or studies could be said to exert major or undue influences on the overall pattern of results.

The largest change in ratios would come from dropping the study of Mills (1995)—removing this study would increase the overall ratio of negative to positive findings from 1.58:1 to 1.82:1—yet such a change would scarcely be surprising: Mills focuses on incomes, and as noted earlier, incomes provide a consistently more favorable picture of overall socioeconomic outcomes than do

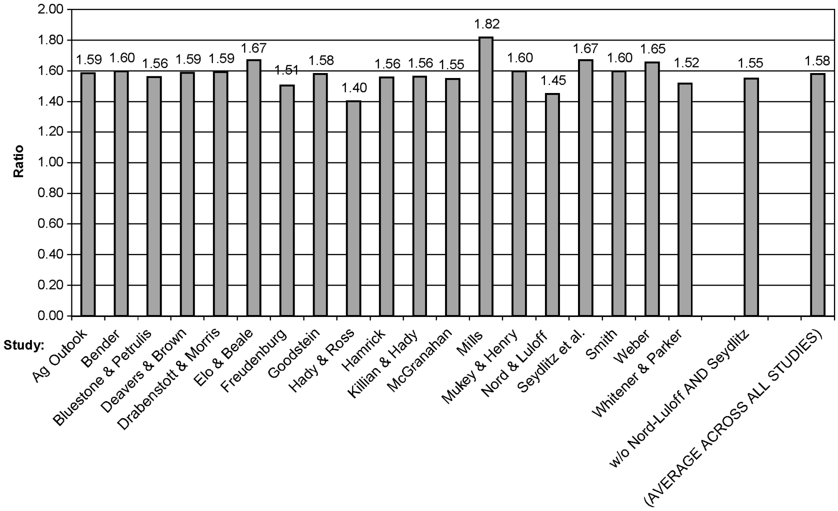

Figure 5

Ratios of adverse to favorable findings without the indicated sources.

poverty or unemployment rates, or for that matter, the overall distributions of findings. The greatest reduction in the overall ratio would come from omitting Hady and Ross (1990); as noted earlier, this study was done as an update to the original report by Bender et al. (1985), and thus it includes a strong emphasis on the years from 1980 onward, when findings have tended to be significantly more negative than in earlier years. Finally, the two studies contributing the largest number of findings are those of Nord and Luloff (1993) and of Seydlitz, Jenkins, and Hampton (1995); these two studies, in combination, provided 141 of the 301 findings just analyzed, but neither of the two studies exerts as much influence in changing the overall total as do Mills (1995) or Hady and Ross (1990), and in combination, the two studies' effects largely counterbalance one another. As can be seen from Figure 5, in other words, the effect of removing the Nord and Luloff findings would be to reduce the overall average from 1.58:1 to 1.45:1, while the effect of removing Seydlitz et al. would be to increase the overall ratio to 1.67:1. As shown by the bar near the extreme right end of the figure, the net effect of removing both studies would be a degree of shift in the overall ratio of negative to positive findings that is remarkably small—a reduction from 1.58:1 to 1.55:1.

Still, in the interest of caution, it should be noted that there would be one clear effect of removing one or both of these studies that is not reflected in Figure 5: Partly because both Nord and Luloff (1993) and Seydlitz et al. (1995) used tests of statistical significance to assess whether findings were positive, negative, or indeterminate, these two studies reported a higher proportion of "indeterminate" outcomes than for the studies that did not use statistical significance tests. Except for these apparently minor variations, however, the simple form of sensitivity analysis presented in Figure 5 shows a considerable degree of robustness in the comparison that is likely to prove most salient to readers, involving the ratio between negative and positive findings. Indeed, there is no other study of the 19 included in the final analysis that has enough of an effect on the overall findings that the removal of that study would shift the overall ratio of negative to positive findings by as much as 0.10; instead, the overall ratio would stay within the range of 1.58 (± 0.10):1.

Variations by Region and Era

Despite the fact that the overall patterns of findings appear to be relatively robust, the existing literature suggests that more finely grained patterns may be present, as well. Given our earlier warnings about the many variations across studies, plus the exploratory nature of any further comparisons, our judgement is that further tests of statistical significance would be inappropriate for these more fine-grained assessments, but there is still a need to ask whether the findings differ systematically in other ways. In particular, given the number of findings that have come from the western "energy boomtowns" of the late 1970s and early 1980s, there is a need to consider whether the available findings differ systematically by region and/or by era.

Regional Variation. As noted by Nord and Luloff (1993), the question of regional differences is particularly relevant in light of the number of mines in the western United States that are new, that use open-pit mining techniques, and that exploit particularly rich deposits of easily accessible coal. As can be seen from Figure 6A, which summarizes the variations in findings across regions, the western mines are indeed associated with the most favorable economic findings. Only in the western United States, in other words, do the available studies provide more favorable findings than adverse ones; in the west, just over half of the 73 available findings are favorable, while 27.4 percent are adverse, and the remaining 20.5 percent are neutral. Findings from the south point to greater economic distress, with 37.2 percent of the findings indicating adverse conditions in mining regions, but only 15.4 percent indicating favorable conditions. The 31 available findings from the Great Lakes region point to even greater distress: Only two of the quantitative findings from this region (6.5%) indicate mining to be associated with favorable economic outcomes; instead, most of the available findings are split into roughly equal numbers of "neutral" and "adverse" outcomes. Finally, the results from "other" regions of the country, or from the nation as a whole, point to conditions in mining areas that are more than twice as likely to be adverse (63.0%) than to be favorable (30.3%), while the remaining 6.7% of the findings show no differences.

Differences across Eras. Figure 6B responds to another need that was pointed out earlier—the need to assess potential changes in the relationships between mining and economic well-being over time. Although the preliminary findings from Bender et al. (1985) were relatively favorable, for example, subsequent studies indicated that those preliminary findings may have reflected the unusually prosperous or "boom" conditions that existed in many mining regions during the mid- to late-1970s.

As any number of authors have noted (see, e.g., Gulliford 1989), the era of "western energy boomtowns" came to an unexpectedly abrupt halt on a date that many residents of the Rocky Mountain region still remember as "Black Sunday"—May 2, 1982—when Exxon shut down its massive oil shale operations near Parachute, Colorado, and the mining-dependent portions of the region suddenly found themselves in a deep bust, with no "next boom" on the horizon. While many oil-extraction regions managed to avoid a serious bust for a few more years, largely because oil prices initially avoided the declines that characterized so many other commodities during the early 1980s, world oil prices ultimately dropped from $24.51 to just $9.39 per barrel in the 6 months between December 1985 and June 1986, bringing the end of the boom for oil regions as well (Freudenburg and Gramling 1998). Findings from the era that ended by the early 1980s, accordingly, might be expected to be quite different from those that have been documented in more recent years—a possibility that will be considered next.

Two main types of temporal comparisons are included in the available studies. The first involves longitudinal analyses—those that assess change over time within a given mining region or locality. The second involves cross-sectional comparisons—that is, between mining counties/communities and a matched or "control" set of counties/communities, at a given point in time. In the interest of simplicity, we use the end of 1982, after the end of "boom times" in most U.S. mining regions, as our cutoff point, comparing the findings from data collected during the years up through 1982 against those from data collected in 1983 or thereafter. Given that the overall conclusions from longitudinal analyses are inherently shaped by the conditions that prevail at the end of the study period, any longitudinal studies that straddle the 1982–1983 cutoff point are classified here with the other studies in the "1983 and thereafter" category, while the longitudinal studies that began and ended before 1982 are analyzed with the other "1982 and earlier" findings.

As shown in Figure 6B, the era of data collection does indeed appear to exert an important influence on the favorability of findings. In the years up through 1982, there were more favorable findings (52 of the 123 findings, or

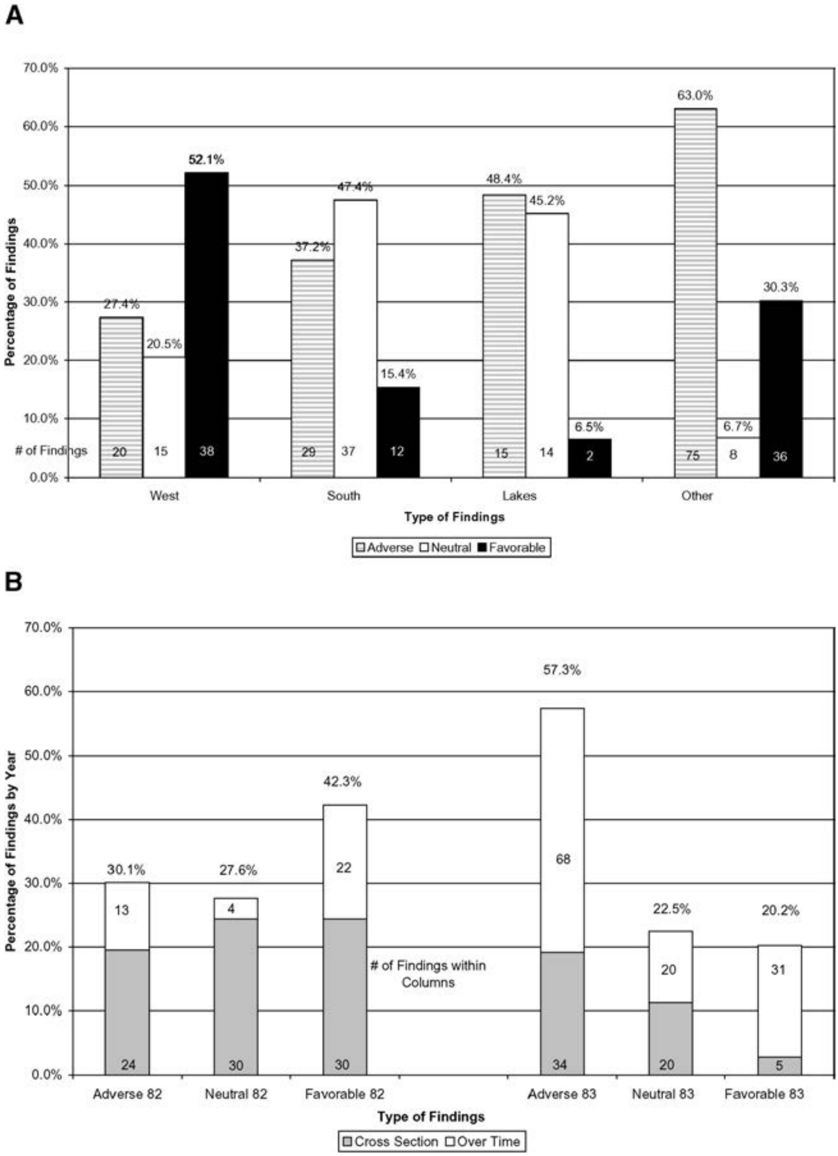

Figure 6
(A) Summary of findings by region. (B) Summary of findings by time.

42.3% of the total) than adverse or neutral ones (37 and 34 findings, or 30.1% and 27.6% of the total, respectively). In the years since then, however, the picture has been much less favorable. An outright majority of the findings since 1982 have been adverse, with 102 adverse findings constituting 57.3 percent of the 178 available findings for the era since 1982. While favorable findings were the most common category for studies that focused on the "boom" conditions that existed up until early 1982, in fact, favorable findings make up the smallest category of the findings since then—just 36 such findings, or 20.2 percent of the total—meaning that there are only about one-third as many favorable findings as adverse ones in studies using data from the years since 1982.

While the cross-sectional findings do not allow us to assess actual change over time in mining areas, a small number of studies have reported "before and after" or longitudinal findings; these findings are reported in the unshaded portions of the bars of Figure 6B, and they do indeed indicate mining to be associated with declining local economic conditions. Intriguingly, save for the fact that the longitudinal studies appear to have produced fewer neutral findings, proportionately, than have the cross-sectional studies (particularly for findings from 1982 and earlier), Figure 6B shows that the overall conclusions suggested by the two different types of methods appear broadly similar to one another, particularly with respect to the dramatic differences between findings from the "boom" era that ended in roughly 1982 and the less "euphoric" times (Gulliford 1989) that have characterized U.S. mining regions ever since. The 68 adverse findings from longitudinal studies, for example, represent 56.2 percent of the 121 longitudinal findings for the period from 1983 to present, while the 34 adverse findings using cross-sectional data represent 57.6 percent of the 59 cross-sectional findings for the same period.

Table 2 presents a summary of the comparisons that are illustrated in Figure 6, doing so in a format that mirrors that of Table 1. As can be seen from a closer examination of the findings from the two tables, most of the more favorable conclusions about economic conditions in mining areas come from a relatively small subset of the available findings—principally those focusing on incomes, in the western United States, before the end of 1982. As shown earlier by Table 1, in other words, only 88 of the 301 findings indicate favorable economic conditions in mining regions, and the clear majority of those findings (56 of the 88, or 63.6% of all favorable findings) involve incomes. Of the greater number of findings that have to do with poverty or unemployment, less than one-fifth—just 32 of the 183 (12+20 of the 59+124), or 17.5 percent—are favorable.

As shown in the top half of Table 2, similarly, it is only in the data from the western United States that favorable outcomes make up as many as one-third of the available findings; across the other regions of the United States as a whole, only 50 of the 228 remaining findings, or 21.9 percent of the total, are favorable, while another 119 findings—52.2 percent, or an actual majority of the remaining 228 findings—point to adverse economic conditions in mining areas. As just noted, finally, the bottom half of Table 2 shows that findings of favorable economic conditions in mining regions have become relatively rare since 1982, making up only about 20 percent of the available findings that come from 1983 and thereafter, while adverse findings make up nearly three times that number, or 57.3 percent of the overall total, for the same era.

Discussion and Conclusions

These analyses strongly support the warnings of those who have expressed skepticism about the socioeconomic benefits of mines. There are clearly more positive than negative findings for incomes, but the only way for this pattern to be statistically significant is for the neutral findings to be treated explicitly as positive ones. By contrast, for the other three main categories of findings—those for poverty, unemployment, and overall—the test results are strongly significant, statistically, in the opposite direction, indicating that adverse economic outcomes are significantly more likely in the accumulated research literature to date than are positive ones. These findings for poverty, unemployment, and overall patterns remain significant when neutral findings are omitted from the analysis, and not just when the neutral findings are treated as negative ones.

Our findings also reinforce the warnings of Nord and Luloff (1993), who note the importance of analyzing the differences in findings across regions and across time; like Nord and Luloff, we find the problems to be particularly severe in the older eastern and nonfuel mining areas. In addition, our findings mirror what Elo and Beale (1985) called a "curious anomaly"—with mining-dependent counties in that study having had higher median incomes, but also higher proportions of households living in poverty. Our results, in other words, also indicate that, even when higher incomes are associated with mining, those incomes do not prove sufficient to alleviate the problems of poverty and unemployment so often associated with mining-dependent regions.

As a reviewer has noted, one partial explanation for the "anomaly" may involve the mechanization that has had particularly strong impacts on mining employment and income inequality in Appalachia. Mechanization has become associated with relatively high wages in most U.S. mining operations today, but only for the smaller number of workers still employed; many other workers once employed in mining have been displaced by the mechanization. This pattern may well be reinforced by the increasing number of "mining workers" whose jobs are professional and/or technical in nature—geologists, engineers, computer specialists, and so forth—such that the traditional blue-collar "mining jobs" are decreasing in proportion as well as in number.

Table 2
Percentages of Adverse/Neutral/Favorable Findings, by Region and Era

	No. of Findings	% of Category	% of Total
Region			
West			
Adverse	20	27.4	6.6
Neutral	15	20.5	5.0
Favorable	38	52.1	100.0
Total West	73	100.0	24.2
South			
Adverse	29	37.2	9.6
Neutral	37	47.4	12.3
Favorable	12	15.4	4.0
Total South	78	100.0	25.9
Lakes			
Adverse	15	48.4	5.0
Neutral	14	45.2	4.7
Favorable	2	6.5	0.7
Total Lakes	31	100.1	10.4
Other/Nation			
Adverse	75	63.0	24.9
Neutral	8	6.7	2.7
Favorable	36	30.3	12.0
Total Other/Nation	119	100	39.6
Total across Regions	301	NA	100.1
Era			
1982 and before			
Adverse	37	30.1	12.3
Neutral	34	27.6	11.3
Favorable	52	42.3	17.3
Total 1982 and before	123	100.0	40.9

(continued)

Table 2 *(continued)*

	No. of Findings	% of Category	% of Total
1983 and after			
Adverse	102	57.3	33.9
Neutral	40	22.5	13.3
Favorable	36	20.2	12.0
Total 1983 and after	178	100.0	59.1
Total across Eras	301	NA	100.0

Another potential factor behind the apparent anomaly may involve methodological variations: Unlike data on poverty and unemployment rates, which are almost always collected at the level of the households and hence in the communities or counties where people actually live, income data are often collected at the level of the firm—that is, where people work, rather than where they live. The potential importance of this distinction is illustrated by the recently closed White Pine Mine of Michigan's Upper Peninsula (see Wilson 2001). Income data coded by place of work show this mine's county (Ontonagon) to have had far higher incomes than those of Michigan's Upper Peninsula as a whole, but income data based on place of residence, taking cross-county commuting into account, show the same county as being at or below the average of the Upper Peninsula. As shown by recent fieldwork by one of the authors of this article, a key reason is that a significant fraction of the mine's workers lived in different counties or even a different state.

When looking toward the future, perhaps the logical starting point is to note again what this article's analyses do not support–namely, the widespread expectation that mining can be expected to increase the prosperity of isolated rural communities. Indeed, this is perhaps the central implication of our analysis, and one that will require additional examination in future research.

To date, sociologists have offered a number of attempts to explain distressed socioeconomic conditions in resource-dependent areas, drawing on theories of segmented economy, underinvestment in human capital, deindustrialization, and changes in the global economy, as well as on more resource-related or "resource contingency" approaches. Given that the findings of the present study show the experiences of mining communities to have differed significantly from the experiences of other rural regions in recent years, there appears to be a particular need for greater attention to be paid to the last of these approaches—analyzing communities' relationships with the characteristics of natural resources themselves and with the specific technologies that are developed to exploit the resources.

As past studies have noted, most nonmetropolitan communities have little direct control over broader social, demographic, and economic trends, which can include industrial restructuring, the aging of the population, and global recessions (see, e.g., Humphrey et al. 1993; Fitchen 1995; Gaventa 1990). Still, a growing body of research indicates that certain characteristics tend to have important effects on how local economies fare within the broader changes (see, e.g., Baum 1987; Drabenstott and Smith 1995; Garkovich 1989; Malecki 1994). What has been noted in previous work on "resource contingency" (see, e.g., Freudenburg 1992; Freudenburg and Gramling 1998), in a line of logic that is reinforced by the present study's findings, is that there is a need for the range of "local characteristics" to be extended, to include the examination of characteristics of the actual natural resources and of the ways in which they are extracted. To be more specific, there appears to be a need to pay greater attention to the dynamics of resource dependency, over time, such as the potential that, as mines age, the costs of production may rise (and/or the incentive to invest in newer and more efficient technologies may drop). Such changing relationships could well contribute to what Hibbard and Elias (1993) have termed "flickering" operations (characterized by shutdowns during periods of low prices) and to what Freudenburg (1992) has termed the "extraction of concessions"—with workers, communities, and regulators being asked to make wage, tax, and/or regulatory concessions to mining operations in the interest of keeping the mines open.

While we believe our assessment is by far the most systematic appraisal ever to become available for the existing body of research, it is important that our findings be kept in perspective; other studies or methods could potentially come up with more (or less) favorable results—and in any case, it is important that the needed future research in fact be carried out. Our findings, in short, should be interpreted with caution. What is abundantly clear, however, is that caution is also in order for a set of conclusions that have rarely been treated with caution in the past—namely, the common conclusion or in some cases even the strongly asserted conviction that mining must be good for local economies. Despite the intensity with which such beliefs are often stated, the present analysis has shown that there is remarkably little evidence to support them; instead, most of the more systematic approaches to the data point instead to the opposite conclusion, often at high levels of statistical significance.

For the future, in short, it is important that more research be done; for the present, what is perhaps more important is to recognize that it can no longer be responsibly asserted that the socioeconomic impacts of mining for rural communities will be favorable ones. Such findings have always been sporadic at best, and at least since 1982, they have become quite rare. To the extent to which past experience is to be our guide, in other words, there is surprisingly little evidence that mining will bring about economic good times, while there is a good deal of evidence for expecting just the opposite.

ENDNOTES

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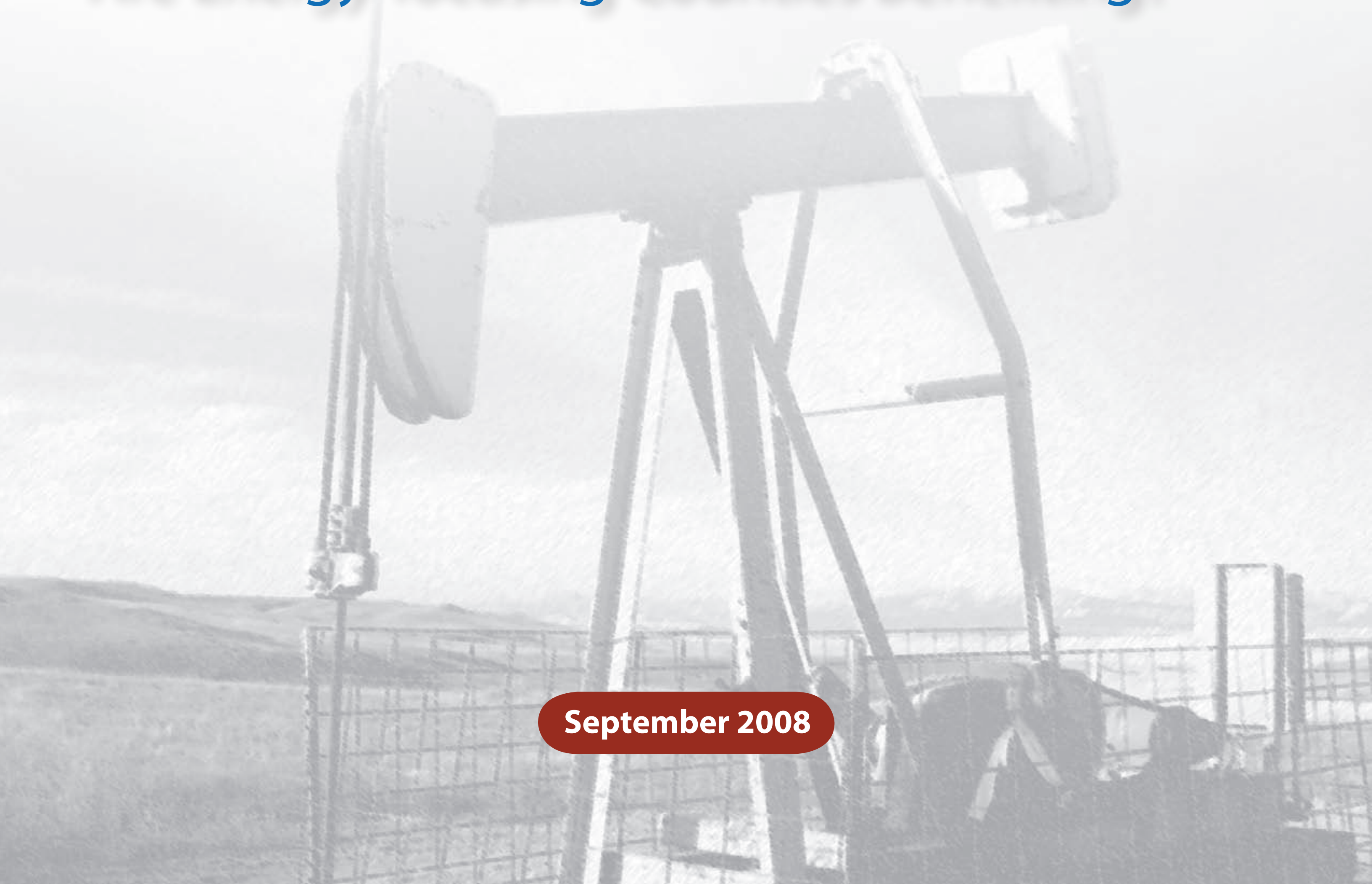
A Report from the ***ENERGY AND THE WEST*** Series by

HEADWATERS ECONOMICS

Fossil Fuel Extraction as a County Economic Development Strategy

Are Energy-focusing Counties Benefiting?



September 2008

Fossil Fuel Extraction as a County Economic Development Strategy

Are Energy-focusing Counties Benefiting?

Headwaters Economics, Bozeman, Montana

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ABOUT HEADWATERS ECONOMICS

Headwaters Economics is an independent, nonprofit research group. Our mission is to improve community development and land management decisions in the West.

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ABOUT THE *ENERGY AND THE WEST* SERIES

This report is the third in a series—*Energy and the West*—published by Headwaters Economics on the topic of energy development. This series is designed to assist the public and public officials in making informed choices about energy development that will benefit the region over the long term.

In forthcoming reports in the *Energy and the West* series, listed below, we cover the policy context for energy development in the West and the resulting impacts to states, counties, and communities viewed from the perspective of economic performance (i.e., jobs, personal income, wages) and fiscal health (i.e., state and county budgets, revenues and expenses). The series also includes state and local area case studies, which highlight benefits and costs in greater detail.

Titles in the *Energy and the West* series:

- Energy Development and the Changing Economy of the West
- U.S. Energy Needs and the Role of Western Public Lands
- Fossil Fuel Extraction as a County Economic Development Strategy: Are Energy-focusing Counties Benefiting?
- Energy Revenue in the Intermountain West: State and Local Taxes and Royalties from Oil, Natural Gas, and Coal
- Impacts of Energy Development in Colorado, with a Case Study of Mesa and Garfield Counties
- Impacts of Energy Development in Wyoming, with a Case Study of Sweetwater County
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- Potential Impacts of Energy Development in New Mexico, with a Case Study of Otero County

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INTRODUCTION

A rapid rise in the price for oil, natural gas, and coal, and a political climate that has favored energy development on public lands has made it possible for some counties in the West to use energy development as a strategy for economic development.

In this report in our *Energy and the West* series, we examine the consequences of focusing on fossil fuel extraction as an economic development strategy. Has it benefited counties in the long run?

The recent rise in fossil fuel development in the West is happening in the context of an economy that has already made a significant shift, away from a historic dependence on resource extraction, to an economy that today is driven primarily by service industries and knowledge-based occupations, and retirement and investment dollars. As a consequence, the economic role of public lands, where much of today's energy development is taking place, has also shifted.

In the past, the principal economic contribution from Bureau of Land Management (BLM), Forest Service, and state lands in the West came from the raw materials that were extracted and exported from the region. Today, there is an additional economic role for public lands. For many communities, the recreational opportunities and scenery provided by public lands are essential components of the quality of life that attracts and retains people and business, as well as retirees and investment income. The scenery, wildlife, and recreation-oriented lifestyle, in which public lands play a critical role, are now economic assets, and a key component of the West's competitive advantage.

The information provided in this report can help those entrusted with the management of the lands in the West to understand the consequences, and potential tradeoffs, of energy development.

Questions Answered in this Report:

1. Has an economic focus on energy development benefited counties of the West?
2. Is today's energy surge any different from the energy boom of the 1970s?
3. Why do energy-focusing counties underperform relative to their peers?

SUMMARY FINDINGS

Key Term: Energy-focusing

We use the term "energy-focusing," abbreviated "EF" in this report, to refer to the 26 rural counties in the West that concentrate their economic development on the extraction of fossil fuels. These counties have a relatively high proportion of total jobs (7% or more) in the county that are involved in the extraction of fossil fuels (natural gas, oil, and coal). We use the term "peers" to describe the remaining 254 western counties of similar size (57,000 people or less). For a full definition of "energy-focusing" (EF) counties and their "peers" see the Methods section on page 4.

Counties that have focused on energy development are underperforming economically compared to peer counties that have little or no energy development.

It is well documented that counties focused on energy extraction as an economic development strategy have historically gone through periods of boom and bust—that their economies are volatile. What is less well understood is how these counties fare economically in the long term.

In the long run, the economies of energy-focusing (EF) counties grow more slowly than the economies of their peers that are not pursuing energy extraction as an economic development strategy.

From 1990 to 2005, for example, the average rate of growth of real personal income in EF counties was 2.3 percent per year, compared to 2.9 percent in the peers. In terms of employment, the average annual growth of EF counties over the same time period was 1.8 percent, compared to 2.3 percent for their peers.

An energy development surge no longer guarantees strong economic performance.

In the energy boom that began in the 1970s and ended in the early 1980s, counties that were focused on energy development, with a high portion of jobs in fossil fuel development, were some of the top economic performers in the West. In today's energy surge, this is no longer the case.

As measured by average annual job growth, only one of 26 EF counties ranks among the top 30 economic performers in the West, while during the last energy boom half were top performers. In addition, more than half of EF counties are losing population in the midst of today's energy surge.

In EF counties, the share of total jobs in energy-related fields has declined, from 23 percent in 1982 (past energy boom) to 14 percent in 2005 (current energy surge). In recent years, jobs unrelated to energy extraction are growing rapidly and the western economy is much larger than in the past.

A heavy reliance on fossil fuel extraction may point to diminished future competitiveness.

As the West develops its fossil fuel energy resources, an ongoing challenge is increasing the competitiveness of local economies, especially in sectors unrelated to energy development.

Compared to their peers in the West that have not pursued energy development as an economic strategy, EF counties over the long term are characterized by:

- Less economic diversity and resilience
- Lower levels of education in the workforce
- A greater gap between high and low income households
- A growing wage disparity between energy-related workers and all other workers
- Less ability to attract investment and retirement dollars

These long-term indicators suggest that relying on fossil fuel extraction may not be an effective economic development strategy for competing in today's growing and more diverse western economy.

METHODS: THE DEFINITION OF ENERGY-FOCUSING (EF) COUNTIES

We define those counties that concentrate their economic strategy on the development of fossil fuels as “energy-focusing” (EF) counties. These are counties where a relatively high proportion of total jobs in the county are involved in the extraction of fossil fuels (natural gas, oil, and coal). Fossil fuel extraction includes the following codes from the North American Industrial Classification System (NAICS): drilling and extracting oil and gas reserves, extracting coal reserves, and support activities related to these. These NAICS codes are shown in Table 1 and are defined in more detail in the Appendix.[1]

Table 1.Description of Data Used to Show Employment and Personal Income Related to Energy Development, by North American Industrial Classification System (NAICS) Code

Description	NAICS Code
Oil and Gas	
Oil and gas extraction	211
Drilling oil and gas wells	213111
Support activities for oil and gas operations (e.g., contract drilling, surveying, mapping, operating oil and gas fields on a contract basis)	213112
Coal	
Coal mining	2121
Support activities for coal mining (e.g., geophysical surveying, mapping)	213113

We define a county as energy-focusing (EF) if more than 7 percent of total private-sector employment in the county was engaged in energy development—natural gas, oil, and coal—in 2005. The 7 percent cut-off was selected for two reasons: (1) below this threshold, the percent of employment in fossil fuel energy sectors in counties across the West falls off rapidly, and (2) any less energy activity as a share of total employment does not reflect a significant concentration on this single industry.

There are 26 EF counties in the West. Table 2 shows the list of EF counties, and their relative concentration in oil and natural gas versus coal extraction. They are all counties with small populations—fewer than 57,000 people. There is one exception: San Juan County, New Mexico. We eliminated San Juan County, New Mexico from the list because it is more than twice as large as the next largest EF county, and we wanted to compare EF counties, which are overwhelmingly rural, with their rural counterparts in the West.

There are 254 “peer” counties in the West. These are western counties of similar size (57,000 people or less) that do not have significant employment devoted to the extraction of oil, natural gas, and coal (less than 7% of total private employment). EF counties (yellow), along with their non-energy “peers” (blue), are shown in Map 1 (page 6).

Of the 26 EF counties in the West, 12 had between 10 percent and 15 percent of all employment engaged in fossil fuel extraction (light green in Table 2), and another eight had more than 15 percent involved in energy development (dark green in Table 2). Four counties had more than 20 percent of all employment in energy development, and one, Campbell County, Wyoming, had a third of its workforce employed directly in energy development.[2]

We used County Business Patterns data, from the Bureau of the Census, to define EF counties. This data does not include individual proprietors (the self-employed), so the actual number of energy workers in a given county will be larger. The ratio of wage and salary workers to proprietors is fairly consistent across industries, so using wage and salary employment numbers does not significantly alter the overall employment share for each industry.[3]

Definition of Mining

When we use the term "mining" in our *Energy and the West* series, we refer primarily to jobs and income associated with the development and extraction of oil, natural gas, and coal (the fossil fuels). Because of restrictions placed on the level of detail available from the U.S. Department of Commerce and the Bureau of the Census, it is sometimes not possible to separate minerals mining from fossil fuels mining. In the energy-focusing counties analyzed in this report, the bulk (over 80%) of "mining" is in energy development.

Table 2. Energy-focusing Counties in the West, 2005

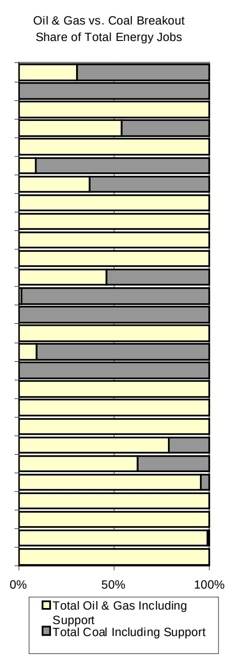
			Oil and Gas Jobs:				Coal Jobs:			
	Energy Jobs in 2005	**Energy Jobs Share of Total Jobs in 2005**	Total Oil & Gas Including Support	Oil and Gas Extraction	Drilling Oil and Gas Wells	Support Activities for Oil and Gas Operations	Total Coal Including Support	Coal Mining	Support Activities for Coal Mining	Population in 2005
Campbell, Wyoming	5,436	**30.0%**	1,656	455	211	990	3,780	3,709	71	37,420
Emery, Utah	668	**24.5%**	2	-	-	2	667	660	7	10,711
Cheyenne, Colorado	99	**21.5%**	99	13	70	15	-	-	-	1,952
Rio Blanco, Colorado	343	**20.9%**	185	49	29	107	158	158	-	6,000
Uinta, Wyoming	1,163	**17.5%**	1,163	247	-	916	-	-	-	19,873
Big Horn, Montana	354	**16.7%**	32	2	-	31	322	322	-	13,076
Converse, Wyoming	610	**16.4%**	227	71	14	142	384	384	-	12,743
Hot Springs, Wyoming	233	**15.4%**	233	36	1	196	-	-	-	4,568
Fallon, Montana	124	**14.9%**	124	72	-	52	-	-	-	2,709
Blaine, Montana	133	**14.1%**	133	-	70	63	-	-	-	6,634
Sublette, Wyoming	309	**14.0%**	309	108	4	197	-	-	-	6,965
Lincoln, Wyoming	639	**13.6%**	294	37	7	250	345	345	-	15,940
Moffat, Colorado	507	**13.5%**	8	2	-	6	499	499	-	13,397
Rosebud, Montana	359	**13.4%**	-	-	-	-	359	359	-	9,279
Lea, New Mexico	2,065	**12.3%**	2,065	447	699	919	-	-	-	56,650
Carbon, Utah	807	**11.5%**	75	44	15	15	733	731	2	19,459
Gunnison, Colorado	689	**11.4%**	-	-	-	-	689	689	-	14,182
Weston, Wyoming	179	**11.2%**	179	87	14	78	-	-	-	6,642
Uintah, Utah	824	**10.9%**	824	195	60	569	-	-	-	27,129
Eddy, New Mexico	1,835	**10.5%**	1,835	798	210	827	-	-	-	51,269
San Juan, New Mexico	3,534	9.5%	2,786	671	500	1,615	748	748	-	125,820
Sweetwater, Wyoming	1,344	**9.0%**	841	217	32	592	502	502	-	38,019
Richland, Montana	317	**8.8%**	303	47	7	249	14	14	-	9,163
Yuma, Colorado	204	**8.4%**	204	17	152	35	-	-	-	9,785
Toole, Montana	124	**7.8%**	124	72	35	17	-	-	-	5,174
Big Horn, Wyoming	175	**7.3%**	174	23	-	150	1	1	-	11,325
Duchesne, Utah	293	**7.0%**	293	99	19	175	-	-	-	15,328

Energy Jobs over 15% of Total

Energy Jobs over 10% of Total

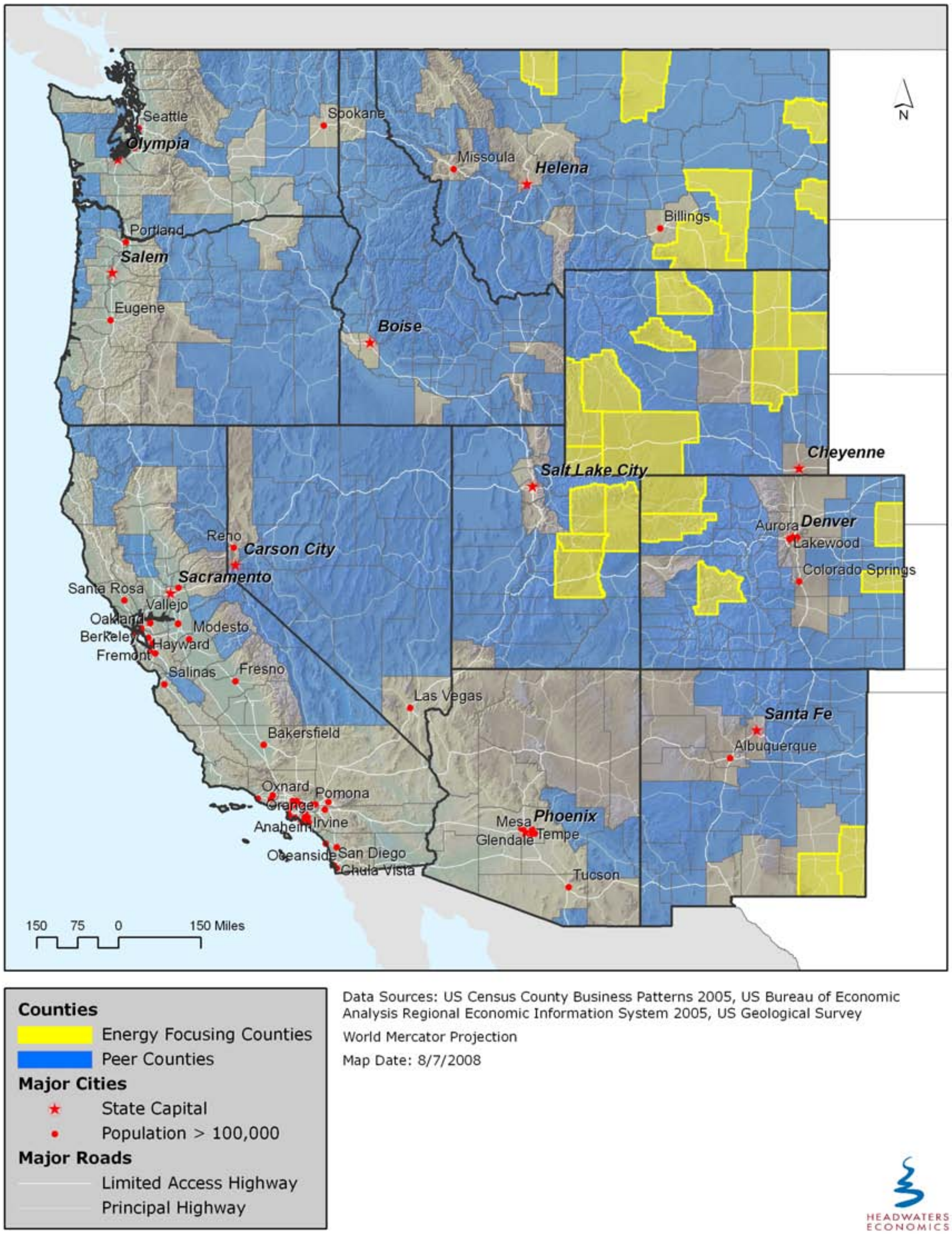
Maximum Population (excl. San Juan) 56,650

San Juan, NM was excluded because population is much larger and we want to focus on small rural communities that are heavily dependent on energy.



EF counties and their peers are shown in Map 1.

Map 1. Energy-focusing Counties and their Rural Peers



HAS AN ECONOMIC FOCUS ON ENERGY DEVELOPMENT BENEFITED COUNTIES OF THE WEST?

In order to answer this question, we compared the economic performance of energy-focusing (EF) counties, measured in a variety of ways, to their rural peers.

We use three time periods for analysis:

1970–1982 A period of economic growth, culminating in a national recession. This period also captures an energy development "boom" period in the West.

1982–1990 A period of recovery in the national economy, but decline, or energy "bust" period, for EF counties in the West.

1990–2005 The beginning of a new period of growth in the national economy, dominated by a shift to a service and knowledge-based economy, an increasingly mobile workforce, and the advent of new technology (personal computers, the Internet, telecommunications). This period also captures the most recent energy surge for parts of the West, which began approximately in 2000.

We use these periods for comparison because they frame starkly different economic stages, and highlight differences as well as emerging similarities between EF counties and their peers.

The measures of performance we used to compare EF counties to their rural peers are:

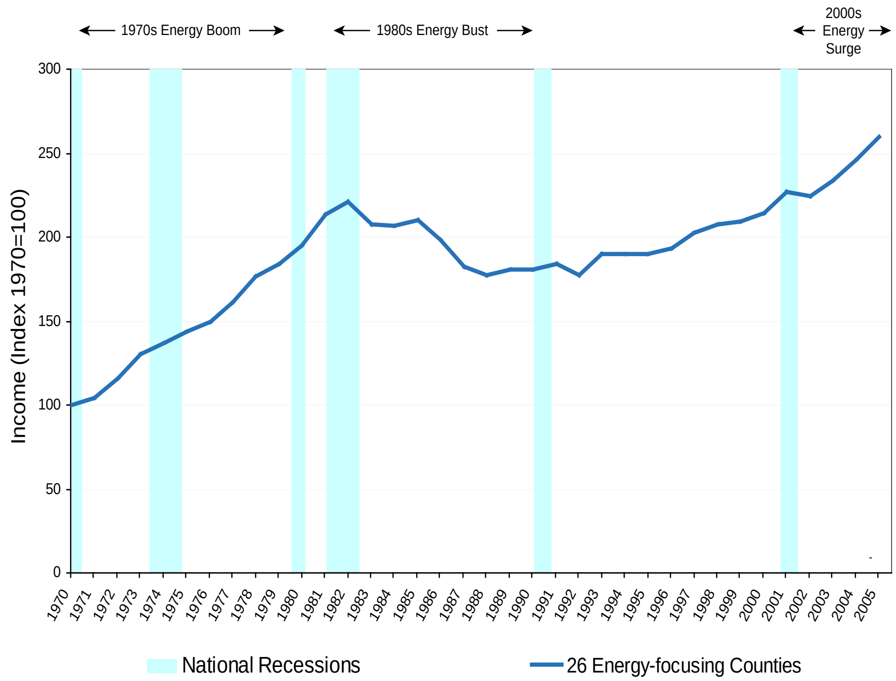
- Total personal income
- Average earnings per job
- Population
- Per capita income
- Employment

Throughout this report all dollars figures are in real terms, i.e., adjusted for inflation.

We begin by looking at the long-term economic history of EF counties. Figure 1 shows the growth and decline of real personal income from 1970 to 2005 in EF counties (in aggregate). Light blue vertical bars illustrate periods of national recession.

The economic history of EF counties is characterized by tremendous volatility. The boom in the 1970s was followed by a bust that lasted a decade in the 1980s. In the 1990s, EF counties recovered. This recovery was fueled by sectors unrelated to energy development, and represents a significant departure from the experience of the 1980s. The steady growth in the 1990s was extended and accelerated in the 2000s, when the current energy surge took root.

Figure 1. Total Personal Income in Energy-focusing (EF) Counties in the West, 1970–2005 (Indexed 1970=100)



Next we examine EF counties as compared to their peers from a historical perspective. Figure 2 shows the trends in personal income, by source (industry and non-labor income sources) from 1970 to 2000, for the aggregate of the 26 EF counties in the West. Figure 3 shows the same information for the aggregate of the 254 rural peer counties in the West.

The differences between the economic experience of EF counties and their peers are starkly evident. While EF counties went through a discernable boom/bust cycle, their peer counties saw a much steadier growth.

From 1970 to 1982, total personal income in EF counties, driven by mining, which includes energy development, grew rapidly. For the rest of the 1980s, mining and energy development contracted severely and brought the rest of the economy down with it. By the 1990s, however, with mining and energy development still declining though beginning to stabilize, the rest of the economy grew—this time independent of the fortunes of mining and energy extraction. Growth in the 1990s was driven by the rise in personal income from people employed in service and professional industries, and the even-faster increase of non-labor income (retirement, investments, government transfer payments, etc.).

For EF counties, the 1990s represented a period of economic diversification. The fact that the economies of EF counties began to diversify, even in the face of rapid declines in the mining (mostly energy development), is an important point. It underscores the economic shift that took place in the rural West between the 1980s and the 1990s, and shows that the context for today's energy surge is an economy that is both larger and more diverse that in the past.

Figure 2. Historical Trends in Personal Income by Source, Energy-focusing (EF) Counties in the West, 1970–2000 [4]

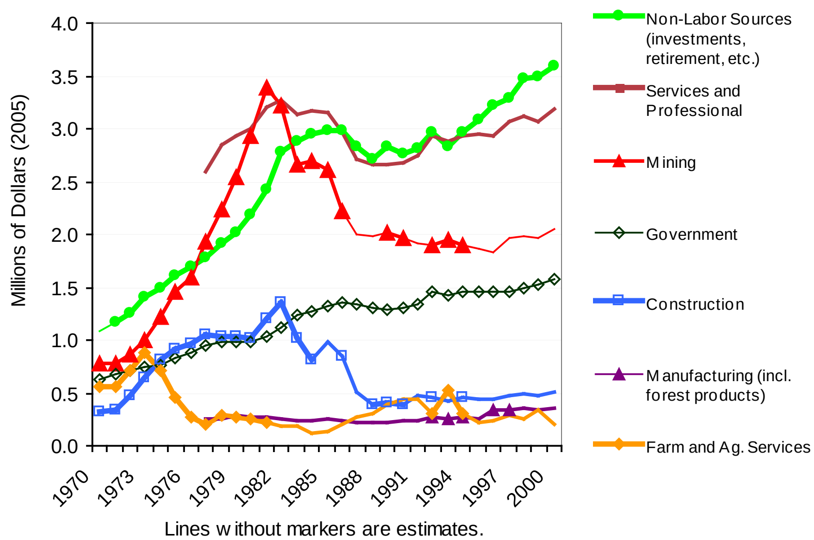
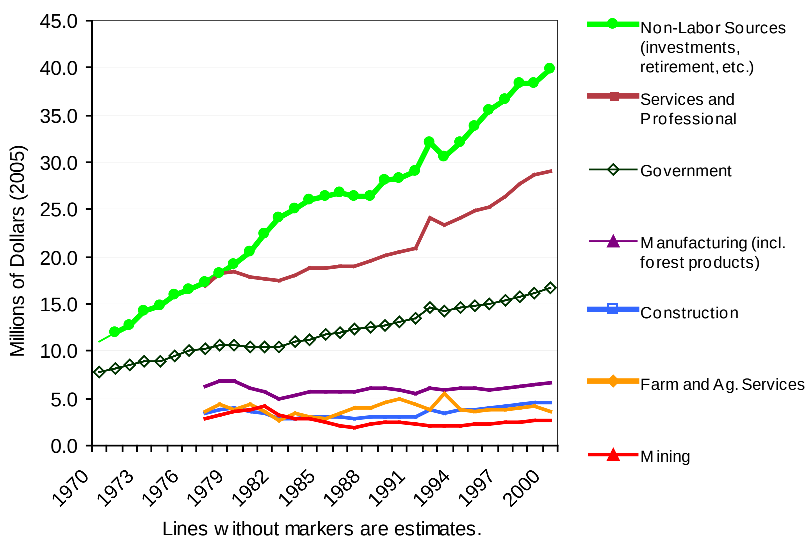


Figure 3: Historical Trends in Personal Income by Source, Peer Counties in the West, 1970–2000 [5]

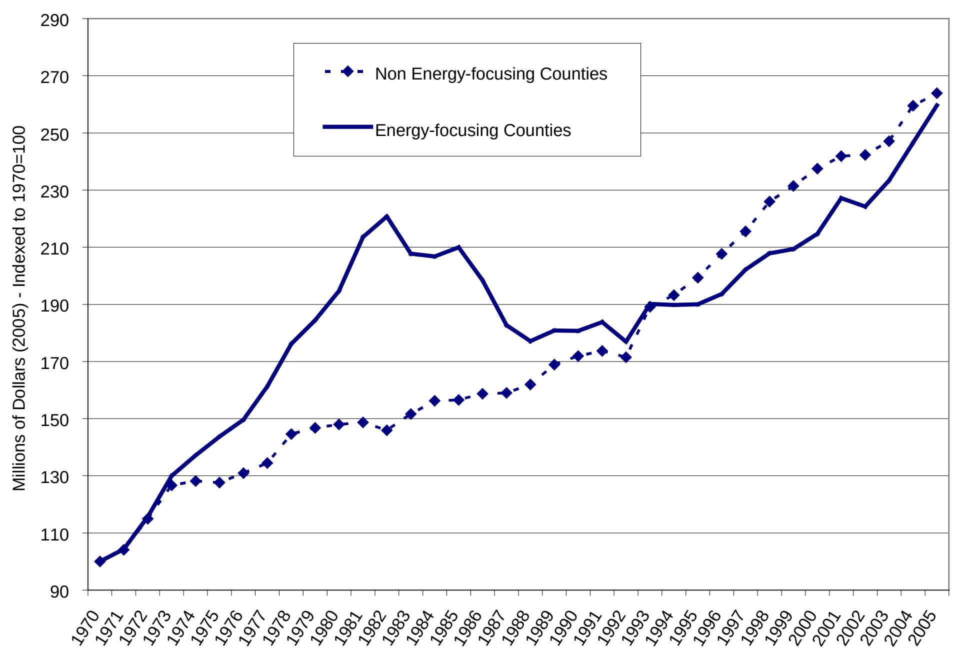


In contrast to EF counties, the non-energy peer counties saw a long and continued growth in real personal income, with no slowdown following the 1982 recession. Traditional industries, ranging from agriculture to manufacturing and construction, were all flat, while service and professional industries, non-labor income, and government enterprises accounted for the growth in personal income.

This tortoise-versus-the-hare comparison shows that it is not necessarily the case that rural counties in the West need to develop energy resources (if they have them) in order to succeed. Both sets of counties—EF counties and their peers—grew their economies at the same rate over the long term. This point is illustrated by Figure 4, which shows the long-term trend in personal income, comparing EF counties to their peer counties. The figure is indexed to 1970 in order to show relative rates of growth.

While the rate of growth in EF counties is characterized by fast acceleration and fast deceleration, the peer counties pursued a steadier expansion, with higher rates of income growth since the early 1990s. From 1990 to 2005, the average rate of real personal income growth in EF counties was 2.3 percent per year, compared to 2.9 percent in the peer counties. For the same time period, the average annual employment growth of EF counties was 1.8 percent, compared to 2.3 percent for the peer counties.[6]

Figure 4. Growth of Total Personal Income, Energy-focusing (EF) Counties versus Peer Counties in the West, Indexed, 1970–2005



These findings show that EF counties have historically gone through periods of boom and bust, outperforming their non-energy peers during the boom, and underperforming during the subsequent bust. They also show that EF counties began to grow and diversify their economies in the 1990s independent of mining and energy development. And, finally, over the last 15 years, EF counties have been falling behind in economic performance compared to their peers.

IS TODAY'S ENERGY SURGE ANY DIFFERENT FROM THE ENERGY BOOM OF THE 1970S?

Figure 5 (page 13) shows measures of economic performance (change in personal income, employment, average earnings per job, population, and per capita income), comparing EF counties to their peers. The vertical bar charts show the difference in growth rates for each measure between the two county types. In the chart, bars above 0.0% (the x-axis) indicate a period when EF counties outperformed the non-EF counties. Bar charts below 0.0% refer to episodes when EF counties underperformed compared to their peers.[7]

During the past energy boom period (1970–1982) EF counties showed fast rates of growth in personal income, employment, average earnings per job, population, and per capita income. This is consistent with Figure 4 that showed a much higher growth rate for EF counties during the 1970s. During the ensuing bust (1982–1990), the reverse occurred, and EF counties saw significant declines in all economic performance indicators relative to their peers.

The most interesting finding of Figure 5 is what occurred from 1990 to 2005, after the last energy bust and before and during the current energy surge, and how different the comparative performance is between the two sets of counties when contrasted with the earlier boom period of the 1970s. Compared to their peer counties in the West, EF counties saw a decline in personal income, employment, and population, and a rise in average earnings per job and per capita income from 1990 to 2005. This means that relative to their peers, EF counties underperformed in terms of the growth of real personal income, employment, and population, and outperformed in terms of the growth in earnings per job and per capita income. In other words, in today's economy there is no guarantee that counties that develop fossil fuel reserves have any significant advantage over those counties without those resources.

What Figure 5 also shows is that economically today's energy surge is different from those of the past. Until 1990, the pattern for EF counties was to do very well during a boom and very poorly during a bust. After 1990, this pattern changed, and it is no longer the case that an energy surge causes those counties with a higher share of economic activity devoted to energy development to outperform their rural peers. In three of the five economic indicators, the EF counties did worse than their peers. For the measures where they outperformed—average earnings per job and per capita income—there was only a modest performance difference (0.6% per year from 1990 to 2005).

The reasons for the difference in relative performance are explored in the next section. In brief, one reason is that the economy of the rural West has grown substantially in the last few decades, and as a result new energy jobs now make up a much smaller percent of total employment than in the past. Figure 6 shows that in EF counties at the peak of the last boom, in 1982, energy-related jobs were 23 percent of total employment (the green line, and right axis in the figure), whereas, in 2005, energy-related jobs in EF counties were 14 percent of total employment.[8] In other words, the relative share of energy jobs in EF counties has declined.

In addition, today's energy surge, driven in part by ready access to public lands, is occurring in a different context. Over the last three decades the economic role of public lands has changed significantly, from a repository of raw materials, to a haven for recreationists, tourists, retirees, and mobile businesses whose owners choose to locate in areas with a high quality of life. The economic transition, from a resource-based economy, to one focused on services, knowledge-based occupations, retirement, and investment dollars, has already taken place.

To put this in perspective, for the West as a whole, service-based occupations and non-labor income constitute 86 percent of the growth in the economy during the last three decades. And today, 45 percent of total personal income comes from wages earned by people employed in service-related occupations, while another 27 percent is from non-labor sources, such as retirement and investments.[9]

Of particular note, given that a new energy development surge started around the beginning of this decade, is the fact that mining, which includes oil, natural gas, and coal development, is still a relatively small component of the economy of the West, providing 1 percent of total personal income in 2005.[10]

The West is the most urbanized part of the U.S., with 90 percent of people living in metropolitan areas.[11] As a result, these trends largely represent urban phenomena. A closer look at the rest of the West—the rural West without metropolitan areas—reveals similar findings.

In the non-metropolitan West, a third of personal income in 2005 was generated by service-related industries. Non-labor income was relatively larger than in the rural West, making up more than 40 percent of total personal income.[12] Mining, including oil and natural gas, constituted less than 5 percent of total personal income and 2 percent of employment.[13]

For a thorough discussion of the economy of the West and the relative role of energy development, please consult another report in our *Energy and the West* series, *Energy Development and the Changing Economy of the West*.

Figure 5. Annual Rates of Growth of Key Economic Indicators, Shown as the Difference in Growth Rates Between Energy-focusing (EF) Counties and their Peers in the Rural West

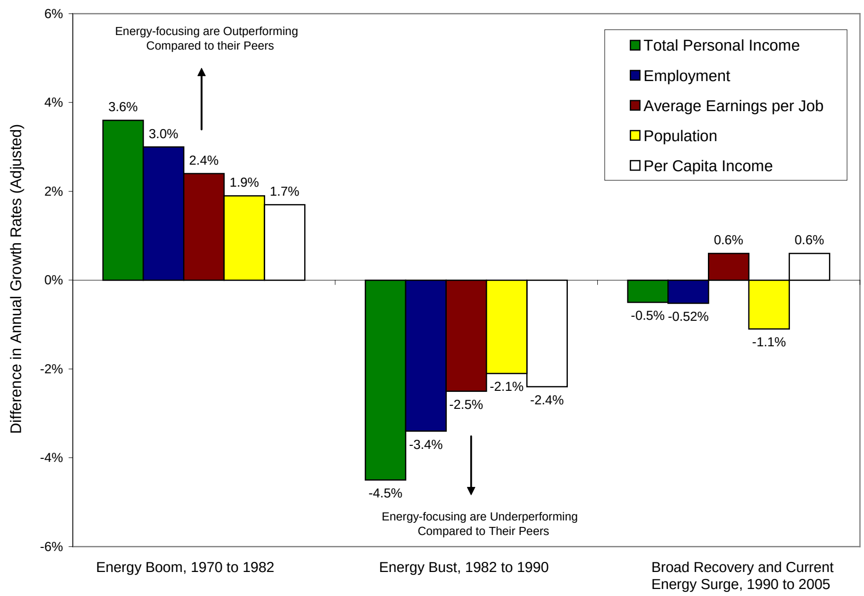
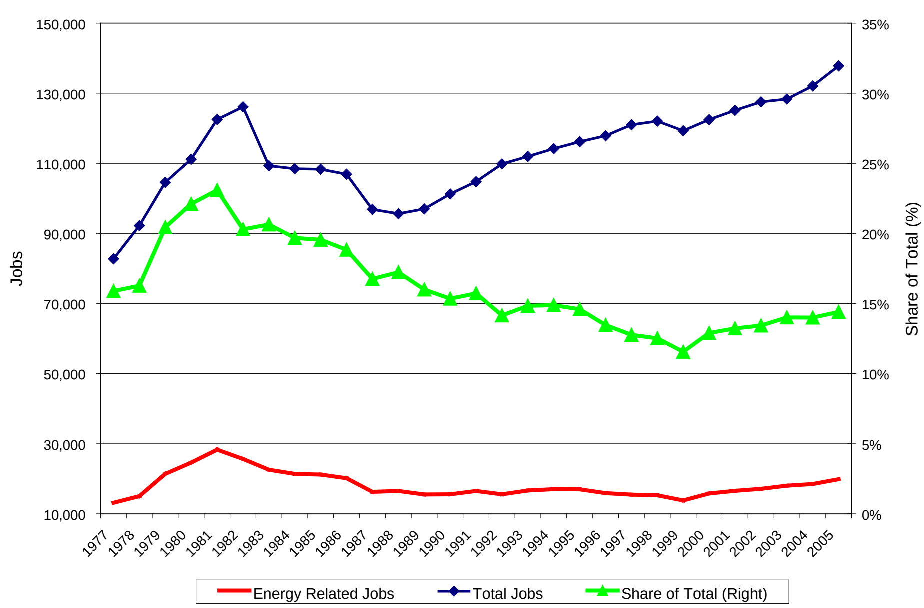


Figure 6. Energy-related Jobs in the Energy-focusing (EF) Counties in the West, as Share of Total, 1977–2005



The scale of the recent economic transition means that it is more difficult today for energy development, by itself, to turn county economies into top economic performers. This is illustrated in Table 3, which ranks EF counties among all counties in the West according to the annual growth of jobs during three time periods. In the energy boom that took place from 1970 to 1982, 10 of the 26 EF counties were in the top 30 counties in the West in terms of job growth (light green). Only one, Toole County, Montana, was among the bottom 30 counties (orange).[14]

During the ensuing bust, from 1982 to 1990, 12 of 26 EF counties ranked among the bottom 30 counties in the West in terms of job growth, and none were top performers. This is consistent with previous figures that showed significant economic decline for EF counties during this period.

The current energy surge has not created a rising tide lifting all EF boats as in the past. Only one county, Sublette County, Wyoming, ranks among the top economic performers in the West, in terms of job growth. Campbell County, Wyoming, the most energy-focusing county in the West, had the third highest rate of growth in the past energy boom, but ranks 85th in overall job growth in the current surge. Emery County, Utah ranked fifth in the past boom, and is 331st in the current surge. Even Sweetwater County, Wyoming, which is in the midst of a boom in natural gas development, ranks 254 out of 411 in terms of job growth during the current energy surge, as compared to fourth in the last boom.

Table 3. Ranking of Energy-focusing Counties Among all Counties in the West, in Terms of Average Annual Job Growth

			Rank among 411 western counties, based on average annual job growth during:		
Sorted by Energy Dependence:	Energy Jobs in 2005	Energy Share of Total (2005)	Old Boom: 1970-1982	Bust: 1982-1990	Recent Boom: 2000-2005
Campbell, Wyoming	5,436	30.0%	3	402	85
Emery, Utah	668	24.5%	5	385	331
Cheyenne, Colorado	99	21.5%	240	327	384
Rio Blanco, Colorado	343	20.9%	31	411	237
Uinta, Wyoming	1,163	17.5%	6	370	139
Big Horn, Montana	354	16.7%	296	348	202
Converse, Wyoming	610	16.4%	14	391	112
Hot Springs, Wyoming	233	15.4%	161	380	304
Fallon, Montana	124	14.9%	280	399	301
Blaine, Montana	133	14.1%	367	270	366
Sublette, Wyoming	309	14.0%	157	326	28
Lincoln, Wyoming	639	13.6%	149	353	110
Moffat, Colorado	507	13.5%	23	358	221
Rosebud, Montana	359	13.4%	7	390	375
Lea, New Mexico	2,065	12.3%	87	403	228
Carbon, Utah	807	11.5%	29	405	327
Gunnison, Colorado	689	11.4%	54	274	36
Weston, Wyoming	179	11.2%	116	382	215
Uintah, Utah	824	10.9%	28	393	88
Eddy, New Mexico	1,835	10.5%	136	351	224
Sweetwater, Wyoming	1,344	9.0%	4	386	254
Richland, Montana	317	8.8%	104	408	321
Yuma, Colorado	204	8.4%	289	131	398
Toole, Montana	124	7.8%	386	299	372
Big Horn, Wyoming	175	7.3%	205	374	278
Duchesne, Utah	293	7.0%	22	375	102

Top 30 (out of 411 Western Counties)
Bottom 30 (out of 411 Western Counties)

In spite of the recent rise in energy development activity, most EF counties are experiencing population losses. Table 4 (page 16) shows that of the 26 EF counties, 10 (38%) have seen an increase in population from 2000 to 2007 (highlighted in green). This includes some of the most heavily energy-focusing counties in Wyoming, Utah, and Colorado. Surprisingly, 16 (62%) of the energy-focusing counties lost population during the same period.[15]

Strangely, six of the counties that lost population at the same time added over 100 new jobs (not counting proprietors), from 2000 to 2005, in energy-related fields. These are: Blaine, Richland, and Rosebud counties, Montana; Eddy and Lea counties, New Mexico; and Uinta County, Wyoming.

Why are these counties losing population in the midst of an energy surge? One possible explanation may be the rising cost of living, which we discuss in more detail in the case study reports. As new jobs are created in the fields of oil, natural gas, and coal mining, workers move in, the cost of labor rises, and with a limited supply of housing, the cost of housing rises along with it. Non-energy workers, unable to compete for housing and a higher cost of living, leave. For example, rental prices in Rock Springs, Wyoming, in Sweetwater County, an EF county that is growing rapidly because of energy development, increased by 100% between 2000 and 2007.[16]

Further Reading

For more detail on the impacts of rapid energy development, see the two reports in the *Energy and the West* series listed below. They are available at: www.headwaterseconomics.org/energy.

Impacts of Energy Development in Colorado, with a Case Study of Mesa and Garfield Counties

Impacts of Energy Development in Wyoming, with a Case Study of Sweetwater County

Another possible explanation is that communities in the midst of an energy surge may displace other residents, retirees for example, who do not wish to live in what is becoming for many former rural towns a fast-paced industrial landscape. There may be other reasons for the loss of population that have nothing to do with energy development, and more to do with the plight of rural communities in general. Regardless of the reasons, there appears to be no guarantee that making a choice to focus economic activity on energy development will stem the loss of population that is so common in the rural West.

Table 4 . Net Migration per Thousand People per Year in Energy-focusing (EF) Counties, 2000–2007

	Migration 2000 to 2007 (People per 1000 per year)
Sublette, Wyoming	36.9
Campbell, Wyoming	14.8
Lincoln, Wyoming	8.0
Uintah, Utah	7.1
Converse, Wyoming	4.6
Duchesne, Utah	4.6
Weston, Wyoming	4.5
Gunnison, Colorado	2.7
Rio Blanco, Colorado	0.5
Lea, New Mexico	-1.8
Moffat, Colorado	-2.0
Sweetwater, Wyoming	-2.2
Big Horn, Wyoming	-2.9
Hot Springs, Wyoming	-4.4
Eddy, New Mexico	-4.7
Yuma, Colorado	-5.6
Uinta, Wyoming	-5.9
Richland, Montana	-6.0
Fallon, Montana	-8.2
Toole, Montana	-9.2
Carbon, Utah	-10.6
Big Horn, Montana	-10.9
Rosebud, Montana	-13.0
Emery, Utah	-15.9
Blaine, Montana	-16.5
Cheyenne, Colorado	-32.6
Unweighted Average	-2.6

These findings show that rural economies focusing on energy development today are very different than in the past. Unlike the past, EF counties are underperforming compared to their rural peers. EF counties are not the West's top economic performers they used to be. Today, only one EF county ranks among the top 30 economic performers in the West, while during the last energy boom half were top performers. Energy development also plays a smaller relative role in EF counties than in the past. The share of total jobs in energy-related fields in EF counties has declined, from a high of 23 percent in 1982 (peak of last energy boom) to 14 percent in 2005 (in the midst of today's energy surge). At the same time, 62 percent of EF counties are losing population in the midst of today's energy surge.

WHY DO ENERGY-FOCUSING COUNTIES UNDERPERFORM RELATIVE TO THEIR PEERS?

In this section, we explore answers to the question of why EF counties underperform economically.

Energy-focusing Counties are Less Economically Diverse

The more diverse the economy of a county, the better it is able to adapt to the constantly changing conditions of the global and national economy.[17]

There are indications that EF counties are diversifying. Figure 2 (page 9), for example, shows a rise in certain sectors of the economy, such as services and non-labor income, despite declines in mining, including energy development. Figure 2 shows that the relative contribution of mining is declining, in part, because the overall non-energy related portion of the economy is growing. In spite of this diversification, by 2000 (the beginning of the current surge) EF counties were still much less diverse economically than their non-EF peers.

To measure economic diversity we developed a specialization index for the aggregate economy of all 26 EF counties and compared that to one developed for the 254 peer counties in the West.[18] This index is commonly used as a measure of industrial specialization in the economy. Counties with a high specialization index are less economically diverse, more susceptible to volatility, and less innovative.[19] The most diverse score possible would be one that exactly emulated the U.S. economy, and would have a score of 0.0.[20]

Our findings show that in 2000, the specialization index for EF counties was 280, compared to a score of 106 for their peer counties. The principal ways EF counties are different from the U.S. are: a heavy reliance on mining and energy development (11.8% of total compared to 0.4% for the U.S.); under-reliance on manufacturing (4.3% compared to 14.1% for the U.S.); and under-reliance on professional scientific and technical services (2.4% compared to 5.9% for the U.S.). The main ways the peer counties in the West differ from the U.S. are: under-reliance on manufacturing (7.9%); over-reliance on agriculture, forestry and fishing (7.2% compared to 1.5% for the U.S.), and over-reliance on accommodation and food services (8.6% compared to 6.1% for the U.S.).[21]

Another way to represent economic diversity is to assess those industries that are growing, and those that are in decline. Table 5 shows the growth of jobs during the current energy surge (2000 to 2005), comparing EF counties to their peers in the West.[22]

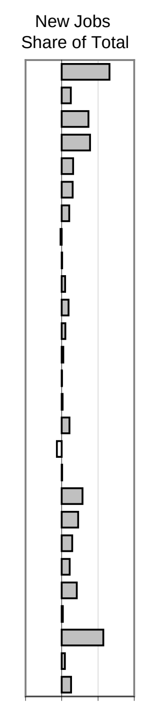
In EF counties, the principal growth (indicated in light green when over 5% of new jobs) was in direct energy-related occupations (energy, mining, support activities for oil and natural gas operations) and largely in occupations indirectly associated with energy development (manufacturing, construction, transportation, warehousing, and professional and scientific services). Other sectors, such as retail trade, health care and social assistance, and accommodation and food services also grew.

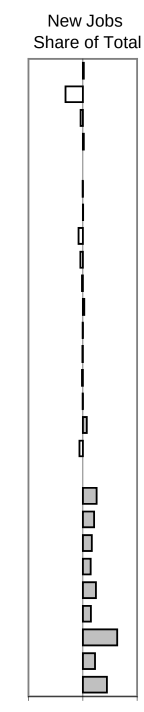
In the peer counties, the bulk of the job growth came from service-related occupations, with the largest growth in health and social assistance, and accommodation and food services. Other areas in which the peer counties grew include construction, transportation and warehousing, retail trade, real estate, and other services. In addition, other data, detailed below, show that peer counties are more successfully attracting investment and retirement dollars, and diversifying their economies with these income streams.[23]

The difference in types of growth can be seen in the column at the far right of Table 5. EF counties are specializing, adding those sectors that are necessary for the exploration, development, extraction, and transportation of fossil fuels. They do not create many new jobs that characterize the broader economic shift in the western economy over the last several decades, namely the development of a service-based and knowledge-based economy.

Table 5. New Jobs by Industrial Sector Comparing Energy-focusing Counties to Peer Counties in the West, 2000–2005

	26 Energy-Focusing Counties		254 Non Energy-Focusing Counties	
Industry	New Jobs 2000-2005	New Jobs Share of Total	New Jobs 2000-2005	New Jobs Share of Total
	15,312	100.0%	62,320	100.0%
Energy	4,043	26.4%	643	1.0%
Manufacturing	775	5.1%	(9,873)	-15.8%
Mining	2,249	14.7%	(1,234)	-2.0%
Support Activities for Oil and Gas Operations	2,387	15.6%	599	1.0%
Management of Companies and Enterprises	969	6.3%	103	0.2%
Drilling Oil and Gas Wells	922	6.0%	(7)	0.0%
Oil and Gas Extraction	632	4.1%	170	0.3%
Unclassified	(108)	-0.7%	(2,392)	-3.8%
Forestry, Fishing, Hunting, and Agriculture Support	38	0.3%	(1,440)	-2.3%
Information	284	1.9%	(416)	-0.7%
Other Services (except Public Administration)	567	3.7%	830	1.3%
Utilities	293	1.9%	(60)	-0.1%
Educational Services	131	0.9%	(187)	-0.3%
Wholesale Trade	12	0.1%	(523)	-0.8%
Support Activities for Coal Mining	76	0.5%	(125)	-0.2%
Finance and Insurance	652	4.3%	2,360	3.8%
Auxiliaries, except Corporate, Subsidiary, and Regional M	(412)	-2.7%	(1,930)	-3.1%
Coal Mining	25	0.2%	6	0.0%
Construction	1,756	11.5%	7,969	12.8%
Transportation and Warehousing	1,382	9.0%	6,466	10.4%
Retail Trade	892	5.8%	5,187	8.3%
Administrative and Support and Waste Management and	669	4.4%	4,533	7.3%
Professional, Scientific, and Technical Services	1,261	8.2%	7,484	12.0%
Real Estate and Rental and Leasing	100	0.7%	4,660	7.5%
Health Care and Social Assistance	3,510	22.9%	19,682	31.6%
Arts, Entertainment, and Recreation	262	1.7%	7,026	11.3%
Accommodation and Food Services	789	5.2%	13,778	22.1%





Green if over 5%, Brown if under -5%.

Overall Wages Have Not Increased at the Same Rate as Energy Industry Wages

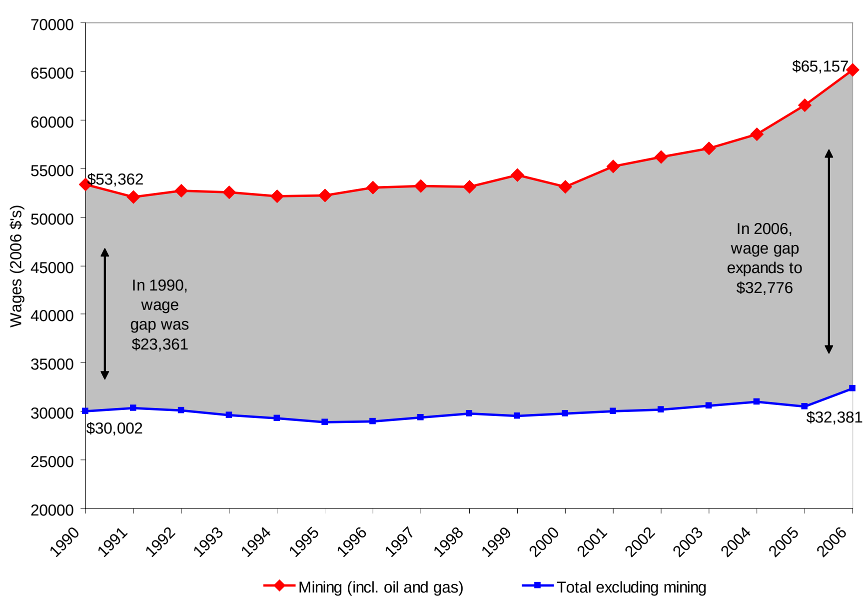
Another possible reason for the relatively lower performance of EF counties is a growing gap between what mine workers earn ("mine" includes energy-related fields in this report) compared to those working in other sectors of the economy.

Figure 7 shows average annual wages of mine workers (primarily oil and natural gas workers) in EF counties, compared to wages in the rest of the economy. In 1990, the wage gap was $23,361; mine workers earned $53,362 per year, on average, while those in other sectors earned, on average, a little over $30,000 per year. Wages in non-mining sectors have not changed much since then. From 1990 to 2006, they grew (in real terms) by 7.9 percent, to $32,381 in 2006. During that time, average annual wages for the mining sector grew by 22 percent, to over $65,000 per year in 2006. The wage gap grew to a difference of $32,776, which is $9,414 more than it was in 1990.[24]

It is possible that the 7.9 percent growth in non-mining wages would not have happened if there weren't any mining activity. From 1990 to 2006, average annual wages in the peer counties grew more slowly, by 6 percent. In 2006, average annual wages in non-mining sectors in the peer counties was $30,555, lower than that of the EF counties, at $32,381.[25]

The growing wage gap in EF counties between mine and all other workers—from $23,361 in 1990 to $32,776 in 2006—is not a healthy sign. The danger is that more people, including teachers, nurses, and farm workers, will be left behind if renewed energy development increases the general cost of living, especially the cost of housing, in a place. We explore this issue in more depth in the case study reports in the *Energy and the West* series.

Figure 7. Average Annual Wages in Mining, including Energy Development, Compared to the Rest of the Economy, in Energy-focusing Counties in the West, 1990-2006



Energy-focusing Counties Have Less Equitable Wealth Distribution

A community where everyone is doing comparatively well stands a higher chance of being able to adapt to change and grow.[26] We measured the gap between "high income" and "low income" by counting the number of households earning more than $150,000 per year ("high income") divided by the number of households earning less than $30,000 per year ("low income") .[27]

At the end of the last energy bust cycle and before EF counties started their economic recovery, in 1990, EF counties had a large gap between high income and low income households: for every household earning over $150,000 per year, there were 108 household earning less than $30,000 per year. By comparison, that same year in the peer counties, for every household earning more than $150,000 per year, there 87 households earning less than $30,000. This means that at the beginning of the recovery period that started in the 1990s, EF counties had a relatively less equitable distribution of wealth; i.e., there were many more "low income" relative to "high income."

Fortunately, by 2000 (at the beginning of the current energy surge, and at the end of the recovery that took place during the 1990s) the high income-low income ratio declined significantly for both county types.[28] In EF counties, for every high income household, there were 27 low income households (a ratio of 1:27; for the peer counties in 2000 the ratio was 1:17).

That EF counties had a larger gap between high income and low income than their peers at the end of a bust period and before embarking on economic recovery (i.e., 1990) is related to the fact that EF counties have not diversified their economies and developed a more mixed suite of service-related industries. By 2000, after a decade of more balanced economic growth, EF counties had improved their earnings distribution, but still lagged behind their peers.

In the current energy surge, EF counties are once again developing an earnings gap among residents. This is attributable to the widening gap between earnings of mine workers and the rest of the economy, a gap that is growing and was over $32,000 in 2006. If cost-of-living factors are considered, it is likely that people on fixed income or earning lower average wages are falling even further behind.

It is premature to estimate what income distribution will look like in EF counties after the current surge, but it is plausible that the gap between the high income and low income households will continue to widen for counties that focus on energy development as a rural development strategy.

Energy-focusing Counties Have Less Educated Workforces

An important condition for economic success in today's U.S. economy is an educated workforce.[29] We look at the percent of the adult population with and without a high school and college education.

At the end of the last energy bust cycle and before EF counties started their economic recovery, in 1990, EF counties had somewhat less educated workforces compared to their peers. In 1990, 24 percent of the adult population in EF counties did not have a high school diploma, which is slightly higher than their peer counties (23%). By 2000, 19 percent of the adult population in the EF counties did not have a high school diploma, an improvement from the previous decade, but still higher than their peers (17%).[30]

In terms of college education, in 1990 the percent of the adult population with a college degree was about equal among the two county types, although slightly less (14% compared to 16%) for EF counties. By 2000, at the end of the 1990s recovery, the percent of the population with a college degree increased slightly for EF counties (to 16%), but remained lower than in the non-EF peers (20%).

These statistics show that counties focused on energy development lag behind their peers in terms of workforce education levels. Even though all counties are experiencing increases in workforce education levels, the proportion of college-educated workers in EF counties at the beginning of this century had been reached by their non-energy peers a decade earlier.

Energy-focusing Counties Attract Fewer Retirement and Investment Dollars

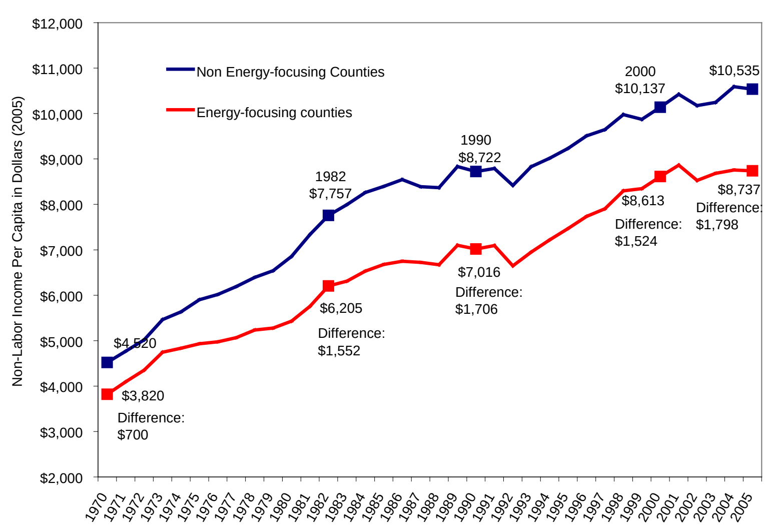
The importance of non-labor sources of income shows no signs of diminishing in the near future. As Americans generate more wealth and our population ages, more people will use their savings, investments, and programs like Social Security to sustain their livelihoods, whether they are still working or retired. By 2005, more than 40 percent of total personal income in the rural West was from non-labor sources, including transfer payments, dividends, interest, and rent.

Non-labor income, when measured on a per capita basis, is a measure of a community's ability to attract and retain this fast-growing segment of the economy.

Figure 8 shows the growth of per capita non-labor income, comparing EF counties to their peers in the West. In 1970, per capita non-labor income was similar between the two county types, with only a $700 difference. By 2005, the difference was $1,798.

These figures show that in the midst of today's energy development surge, counties focusing on energy extraction are less able to attract retirement and investment dollars than their peers.[31]

Figure 8. Growth of Per Capita Non-Labor Income, Energy-focusing Counties Compared to Peers, 1970–2005



These findings show that today's energy surge is different than in the past, and in several important ways EF counties today are less well positioned to compete economically. EF counties are less diverse economically, which makes them less resilient but also means they are less successful at competing for new jobs and income in growing service sectors where most of the West's economic growth has taken place in recent decades. EF counties are also characterized by a greater gap between high and low income households, and between the earnings of mine and energy workers and all other workers. And EF counties are less well educated and attract less investment and retirement income, both important areas for future competiveness.

CONCLUSIONS

In the West today, it is less certain that energy development will bring the prosperity it once did, and reason to be concerned that a concentration on fossil fuel extraction may impair a local economy's ability to grow and compete successfully in today's more diverse economy.

In the past, the pattern of development for counties with fossil fuel reserves was to grow quickly, reach a peak, and then decline sharply—the so-called boom and bust cycle. Beginning in the 1990s, it became clear that the economy in the West was diversifying, with especially rapid job growth occurring in service- and knowledge-based sectors, and that much of the real growth in personal income was associated with this service economy, and an aging population and the influx of retirement and investment dollars.

The implications of these changes—the growth and diversification of the western economy as a whole, including rural areas—is that energy development today does not have the same impact it had in the past. In the 1970s and early 1980s, there were few economic alternatives in rural communities. The discovery and development of oil and natural gas, or coal, created new high-wage jobs where in many cases there had been few or none. By the early 2000s, the West had, with a few exceptions, decoupled from its reliance on resource extraction, and enjoyed a wider range of economic choices than ever before.

The current surge in energy development takes place in this changed economic context. In counties that have pursued energy extraction as an economic development strategy—places we call energy-focusing (EF) in this report—the long-term indicators suggest that relying on fossil fuel extraction is not an effective economic development strategy for competing in today's growing and more diverse western economy.

When compared to their rural peer counties, EF counties suggest an analogy to the fable of the tortoise and the hare. While EF counties race forward and then falter, the non-energy peer counties grow steadily. At the finish line, counties that have focused on broader development choices are better off, with higher rates of growth, more diverse economies, better-educated populations, a smaller gap between high and low income households, and more retirement and investment income.

Economics is the study of how people make choices in a constrained environment. The findings in this report show state and rural leaders, as well as managers of public lands (where much of the energy development is taking place in the West today), that a concentration on fossil fuel development can undercut the competitive position of a regional or local economy.

Further Reading in our Energy and the West *Series*

Learn how energy development impacts:

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APPENDIX

NORTH AMERICAN INDUSTRIAL CLASSIFICATION SYSTEM (NAICS) DEFINITIONS

The language below is copied verbatim from the U.S. Census Bureau's 2002 NAICS Manual
http://www.census.gov/epcd/naics02/index.html

211 Oil and Gas Extraction

Industries in the Oil and Gas Extraction subsector operate and/or develop oil and gas field properties. Such activities may include exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operating separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property. This subsector includes the production of crude petroleum, the mining and extraction of oil from oil shale and oil sands, and the production of natural gas, sulfur recovery from natural gas, and recovery of hydrocarbon liquids.

Establishments in this subsector include those that operate oil and gas wells on their own account or for others on a contract or fee basis. Establishments primarily engaged in providing support services, on a fee or contract basis, required for the drilling or operation of oil and gas wells (except geophysical surveying and mapping, mine site preparation, and construction of oil/gas pipelines) are classified in Subsector 213, Support Activities for Mining.

213111 Drilling Oil and Gas Wells

This U.S. industry comprises establishments primarily engaged in drilling oil and gas wells for others on a contract or fee basis. This industry includes contractors that specialize in spudding in, drilling in, redrilling, and directional drilling.

213112 Support Activities for Oil and Gas Operations

This U.S. industry comprises establishments primarily engaged in performing support activities on a contract or fee basis for oil and gas operations (except site preparation and related construction activities). Services included are exploration (except geophysical surveying and mapping); excavating slush pits and cellars, well surveying; running, cutting, and pulling casings, tubes, and rods; cementing wells, shooting wells; perforating well casings; acidizing and chemically treating wells; and cleaning out, bailing, and swabbing wells.

2121 Coal Mining

This industry comprises establishments primarily engaged in one or more of the following: (1) mining bituminous coal, anthracite, and lignite by underground mining, auger mining, strip mining, culm bank mining, and other surface mining; (2) developing coal mine sites; and (3) beneficiating (i.e., preparing) coal (e.g., cleaning, washing, screening, and sizing coal).

213113 Support Activities for Coal Mining

This U.S. industry comprises establishments primarily engaged in providing support activities for coal mining (except site preparation and related construction activities) on a contract or fee basis. Exploration for coal is included in this industry. Exploration includes traditional prospecting methods, such as taking core samples and making geological observations at prospective sites.

ENDNOTES

[1] U.S. Bureau of the Census, North American Industrial Classification System (NAICS): http://www.census.gov/epcd/www/naics.html.

[2] U.S. Bureau of the Census, *County Business Patterns (CBP), 2008*. Washington, D.C.

[3] The data were derived from statistics published by the Bureau of the Census, in their publication *County Business Patterns* (CBP). We used this data sources primarily because it is devoid of disclosure restrictions. Disclosure restrictions are data gaps, where a government agency will not release information to protect the confidentiality of individual firms, and occur most frequently with data in the Regional Economic Information System (REIS) of the U.S. Department of Commerce. The disadvantage of CBP is that, unlike REIS data, it does not include the self-employed or government employment. If a relative measure is used (i.e., percent of total), as we did, the exclusion of the self-employed or proprietors does not make a significant difference. Some mining sectors employ very few single-owner proprietors, so the inclusion of proprietor's data, if it were available, would actually lower the size of mining relative to other sectors. "Coal mining" and "support activities for mining" are both examples of this, where only 8 percent of the industry is made up of proprietors. Other sectors employ more proprietors than average so the inclusion of proprietors would raise their shares. "Oil and gas extraction" is an example of this, where 12 to 14 percent of employment is in proprietors. Our definition of energy includes all three sectors. Together the differences offset each other and the resultant values for energy's share of total are not affected by the exclusion of proprietors. By using a data set that does not count government employment as part of total, our energy share of total calculations are higher than they would otherwise be, especially in some communities that have a lot of government. If we were to calculate energy shares using both proprietors and government, we expect the results would report shares that were the same or lower.

[4] U.S. Department of Commerce, *Regional Economic Information System (REIS)*, *2008*. Bureau of Economic Analysis. Washington, D.C.

[5] Ibid.

[6] CBP 2008.

[7] Data for figure derived from REIS 2008.

[8] Data for figure derived from CBP 2008.

[9] Ibid, REIS 2008. Mining personal income based on estimates. Employment based on non-disclosed data from Bureau of Labor Statistics, *Quarterly Census of Employment and Wages* (QCEW).

[10] Ibid, REIS 2008.

[11] Bureau of the Census 2008. Calculations based on dividing the total number of people living in metropolitan statistical areas (MSAs) by the total population of the West.

[12] Ibid, REIS 2008.

[13] Ibid, REIS 2008. Mining personal income based on estimates. Employment based on non-disclosed data from Bureau of Labor Statistics, QCEW.

[14] Employment data in table from REIS 2008 and CBP 2008.

[15] Figures in table derived from U.S. Bureau of the Census, 2008.

[16] Housing Data, State of WY Dept of Economic Analysis and Info. http://eadiv.state.wy.us/housing.

[17] For a useful review of the academic literature on economic diversity, see Sterling, Andrew. 1998. "On the Economics and Analysis of Diversity." Electronic Working Papers Series, University of Sussex. http://www.sussex.ac.uk/Units/spru/publications/imprint/sewps/sewp28/sewp28.pdf. More narrowly, consult Malizia, E. E. and K. Shanzai. 2006. "The Influence of Economic Diversity on Unemployment and Stability." Journal of Regional Science. 33(2): 221-235.

[18] The specialization index was calculated by summing the squares of the difference between the aggregate (i.e., 26 EF counties, 254 peer counties) and the U.S. economy:

SPECIALit = ∑ ((EMPijt/EMPit)-(EMPusjt/EMPust)) 2 where,
SPECIALit = specialization of economy in county i in year t
EMPijt = employment in industry j in county i in year t
EMPit = total employment in county i in year t
EMPusjt = employment in industry j in U.S. in year t
EMPust = total employment in U.S. in year t
n = number of industries

[19] For an example of the application of a similar specialization index by the Federal Reserve, see Ozcan-Kalemlt S., B.E. Sorensen and O. Yosha. 2000. "Risk-sharing and Industrial Specialization: Regional and International Evidence." RWP 00-06. Kansas City: Federal Reserve Bank of Kansas City.

[20] The data and calculations for the specialization indices can be found on page 23 of the EF and peer profiles, located on: www.headwaterseconomics/energy.

[21] Data from U.S. Bureau of the Census, 2000, File SF#, Table P48.

[22] Data for the table derived from CBP 2008.

[23] REIS 2008.

[24] Data for figure from Bureau of Labor Statistics (BLS). *Quarterly Census of Employment and Wages (QCEW), 2008.* Washington, D.C. The category "mining" consists primarily of workers involved in the development and extraction of oil, natural gas and coal.

[25] Ibid, BLS 2008.

[26] For a review of the academic literature on the relationship between income distribution and economic growth, see: http://micro5.mscc.huji.ac.il/~melchior/html/Income%20Distribution.htm. More narrowly, consult Henry, C.W. 1998. "Income Inequality, Human Capital Accumulation and Economic Performance." *The Economic Journal*. 108 (Jan): 44-59.

[27] Data from the Bureau of the Census, 1990 and 2000 Decennial Census of Population, and Housing.

[28] The improved ratios were not because there were significantly fewer low-income families in 2000. Rather, the number of high-income families, in both sets of counties, increased. In 1990, 0.9% of household in the EF counties were high-income. By 2000, 2.3% were "rich." By comparison, in 1990 1.1% of the households in the peer counties were high-income. By 2000, 5.4% were high-income.

[29] According to the Bureau of Labor Statistics, earnings are higher and the unemployment rate is lower for people who have high levels of education: http://www.bls.gov/opub/ted/2003/oct/wk3/art04.htm. See also Ray, M. and M. Tucker. 1992. *Thinking for a Living: Education and the Wealth of Nations*. Basic Books, New York, New York.

[30] Data from the Bureau of the Census, 1990 and 2000 Decennial Census of Population, and Housing.

[31] REIS 2008.

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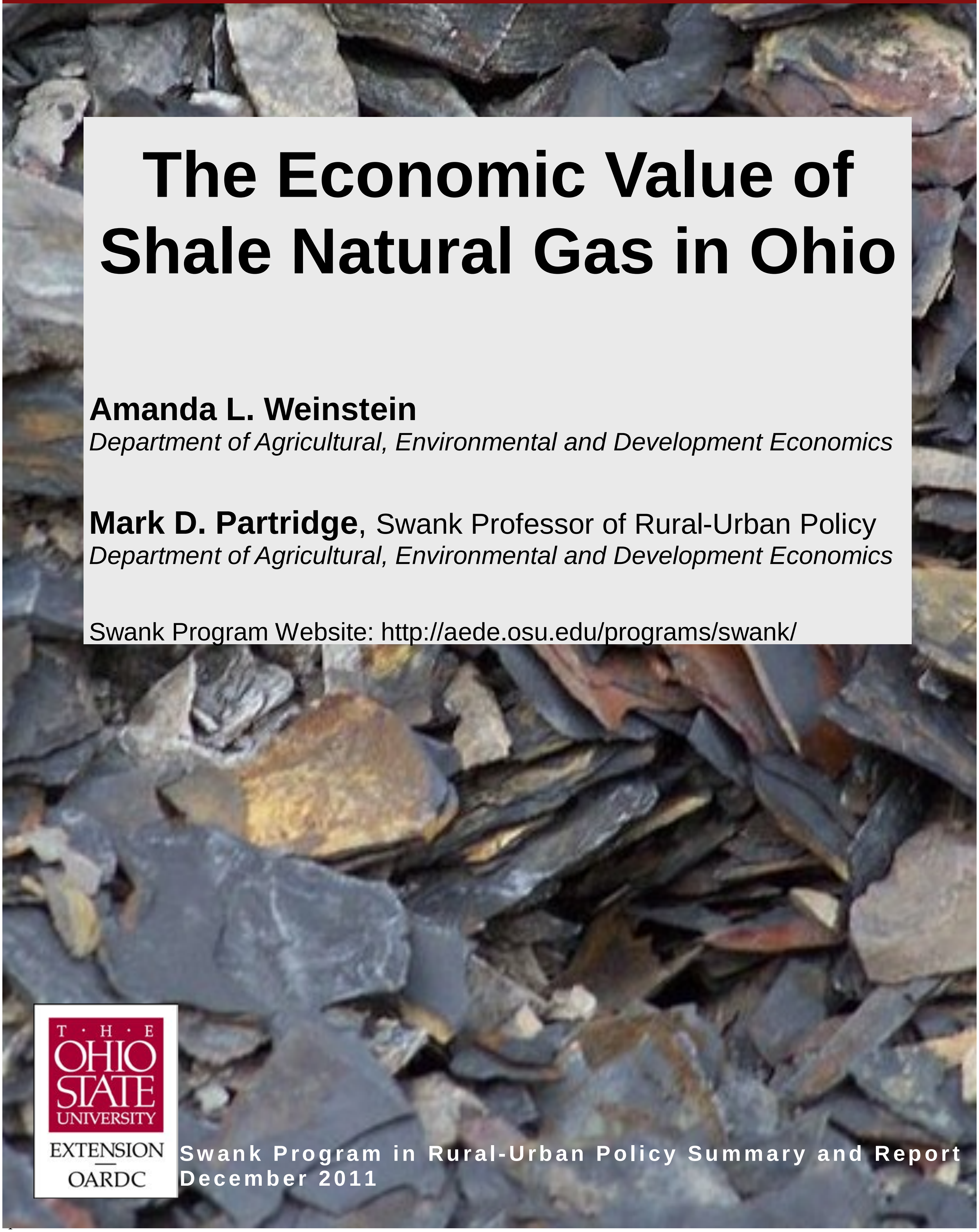

The Economic Value of Shale Natural Gas in Ohio

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Department of Agricultural, Environmental and Development Economics

Swank Program Website: http://aede.osu.edu/programs/swank/

THE OHIO STATE UNIVERSITY EXTENSION — OARDC

Swank Program in Rural-Urban Policy Summary and Report
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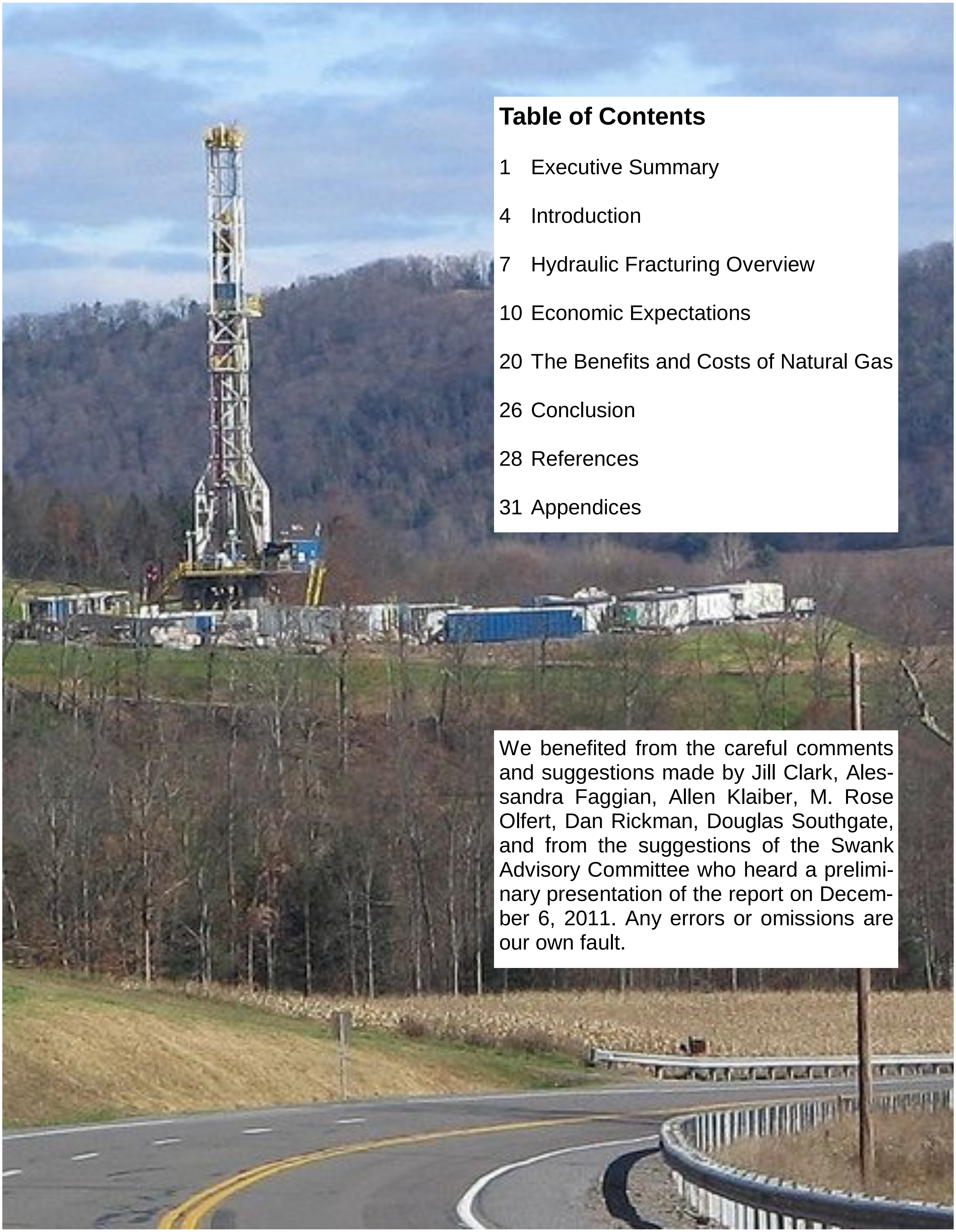
Mark Partridge Short Biography

Dr. Mark Partridge is the Swank Chair of Rural-Urban Policy at Ohio State University. He is a Faculty Research Affiliate, City-Region Studies Centre, University of Alberta, an Affiliate of the Martin Prosperity Center at the University of Toronto, and an adjunct professor at the University of Saskatchewan. Professor Partridge is Managing Co-Editor of the *Journal of Regional Science* and is the Co-editor of new the *Springer Briefs in Regional Science* as well as serves on the editorial boards of *Annals of Regional Science, Growth and Change, Letters in Spatial and Resource Sciences, The Review of Regional Studies, and Region et Developpement*. He has published over 100 scholarly papers and coauthored the book *The Geography of American Poverty: Is there a Role for Place-Based Policy?* Dr. Partridge has consulted with OECD, Federal Reserve Bank of Chicago, Federal Reserve Bank of Cleveland, and various governments in the U.S. and Canada, and the European Commission. Professor Partridge has received funding from many sources including the Appalachian Regional Commission, Brookings Institution, European Commission, Infrastructure Canada, Lincoln Institute of Land Policy, U.S. National Science Foundation, U.S. National Oceanic and Atmospheric Administration, and Social Science and Humanities Research Council of Canada. His research includes investigating rural-urban interdependence and regional growth and policy. Dr. Partridge served as President of the Southern Regional Science Association in 2004-05 and is currently on the Executive Council of the Regional Science Association International (the international governing board).

Amanda Weinstein Short Biography

Amanda Weinstein is a PhD student in the Department of Agricultural, Environmental, and Development Economics at The Ohio State University. Her research as the C. William Swank Graduate Research Associate includes policy briefs about the employment effects of energy policies and general regional growth and policy issues. She is an OECD consultant advising on the economic impacts of alternative energy policies on rural communities. Her other research interests include women's role in economic development examining women's effect on regional productivity growth. She was awarded the Coca-Cola Critical Difference for Women Graduate Studies Grant to continue her work on gender issues in economics. She is also conducting research on the skills most valued during a recession and the impact of military service on intergenerational mobility. Before starting her PhD at OSU, she was a commissioned officer in the United States Air Force after graduating from the United States Air Force Academy. As a Scientific Analyst in the Air Force and then as a Sr. Management Analyst for BearingPoint, she advised Air Force leadership on various acquisition and logistics issues. She is currently an adjunct faculty member of Embry-Riddle University and DeVry.



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We benefited from the careful comments and suggestions made by Jill Clark, Alessandra Faggian, Allen Klaiber, M. Rose Olfert, Dan Rickman, Douglas Southgate, and from the suggestions of the Swank Advisory Committee who heard a preliminary presentation of the report on December 6, 2011. Any errors or omissions are our own fault.

Tower for drilling horizontally into the Marcellus Shale Formation for natural gas in Lycoming County, Pennsylvania.

Executive Summary

Increased production of US natural gas in recent years has helped to meet the growing demands of American customers and has reduced natural gas imports. Natural gas is also a cleaner burning fuel when compared to its most realistic substitute, coal. This substantial increase in production has been attributed in large part due to the development of shale gas through a process called hydraulic fracturing. Hydraulic fracturing has enabled the expansion of natural gas extraction into new undeveloped areas. The Marcellus shale in Pennsylvania has experienced impressive growth in its natural gas industry and neighboring Ohio is beginning down the same path. Proponents argue that among the many purported advantages, natural gas production is associated with significant amounts of new economic activity.

Economists have 150 years of experience in examining energy booms and busts throughout the world to form their expectations of how energy development affects regional economies. Generally, economists find that energy development is associated with small or even negative long-run impacts. They refer to a "natural resources curse" phenomenon associated with the surprisingly poor performance of resource abundant economies. There appears to be more examples like Louisiana, West Virginia, Venezuela, and Nigeria of energy economies seemingly underperforming and few examples of places such as Alberta and Norway of relative over performance. This backdrop needs to be considered in forming good policy in Ohio in order to avoid being in the former group.

In supporting energy development, the natural gas industry has funded its own studies of economic performance. For example, utilizing assumptions derived from Pennsylvania economic impact studies, Kleinhenz & Associates (2011) estimate that the natural gas industry could help "create and support" over 200,000 jobs to Ohio and $14 billion in spending in the next four years. These figures are about the same size as those for Pennsylvania (in industry funded studies). As we outline in this report, impact studies such as those employed by the industry are typically flawed due to the following reasons:

1. Possible double counting economic effects from drilling activities and royalties/lease payments to landowners. Most important, these studies have multipliers well above what independent economists would normally expect.
2. Including unrealistic assumptions about the percentage of spending and hiring that will remain within the state.
3. Ignoring the costs of natural gas extraction on other sectors through higher wages, and land costs that will make them less competitive (e.g., Dutch Disease), as well as environmental damage that limits tourism and other activities. It will also displace coal mining—i.e. more natural gas jobs come at the expense of fewer jobs in coal mining.
4. Often employing out-of-date empirical methodologies that academic economists have long abandoned for better methodologies in terms of evaluation of economic effects.

Many of the same reasons why alternative energy has not been (will not be) a major job creator also applies to natural gas (Weinstein et al., 2010):

1. The energy industry and specifically the natural gas industry's employment share is small and by itself is not a major driver of job growth for an entire state the size of Ohio or Pennsylvania. During the one year span October 2010-October 2011, U.S. Bureau of Labor Statistics data reports that Ohio's unemployment rate fell from 9.7 to 9.0% or 0.7% (without shale development), while Pennsylvania's unemployment rate only fell from 8.5% to 8.1% or 0.4% (with shale development). Ohio also had faster job growth during the span (1.3% versus 1%), showing that shale development by itself is not shaping their growth.
2. It is a capital-intensive industry versus labor-intensive—or a dollar of output is associated with significantly fewer workers.

The costs of natural gas include the effects it has on other industries. Some of these effects include displacement of other forms of economic activity, the effects of pollution that drive out residents who are worried about its effects and the higher wages and land/housing costs that make other sectors less competitive. For example, the tourism industry will likely be adversely affected by fears of pollution and higher wages and costs as other sectors have to compete for workers with the higher paying natural gas sector. In Pennsylvania, for instance, the tourism industry employed approximately 400,000 in 2010 (though a much smaller number is immediately near the shale development) compared to only 26,000 in a broad definition of the natural gas industry (Barth, 2010; BLS). Similar concerns should also apply to Ohio across various sectors of the economy.

Our broad analysis shows the expected employment effects of natural gas are modest in comparison to Ohio's 5.1 million nonfarm employee economy. We show this through (1) an assessment of impact analysis, (2) comparison of drilling counties with similarly matched non-drilling counties in Pennsylvania, (3) statistical regressions on the entire state of Pennsylvania, (4) employment comparisons with North Dakota's Bakkan shale region, and (5) an examination of the employment life cycle effects of natural gas and coal per kilowatt of electricity. Specifically, we estimate that Pennsylvania gained about 20,000 direct, indirect, and induced jobs in the natural gas industry between 2004-2010, which is a far cry fewer than the over 100,000 jobs reported in industry-funded studies (and the 200,000 expected in Ohio by 2015). Given the anticipated size of the boom, Ohio is expected to follow the Pennsylvania's experience. We believe 20,000 jobs would be a more realistic starting point for what to expect in Ohio over the next four years and is in line with what other independent assessments have suggested. However, our 20,000 job estimate does not account for displacement losses in other industries such as tourism, and we also note that local economic effects could appear larger in heavily impacted areas. Moreover, we find that mining counties had considerably faster per-capita income growth than their non-drilling peers, which likely results from royalties/lease payments and the high wages in the industry. Thus, we expect the near-term boom to be associated with frothy increases in income but more temperate job effects.

There are several reasons why the industry-funded studies produce employment results that are considerably different from our estimates. Foremost, impact studies are not viewed as best practice by academic economists and would be rarely used in peer reviewed studies by urban and regional economists. Instead, best practice usually tries to identify a counterfactual of what would have happened <u>without</u> the natural gas industries and compare to what did happen (we adopt two of these approaches). One advantage of identifying the counterfactual is that the estimated effects use actual employment data and are not the estimated outcome of an impact computer model. Yet, like virtually every other economic event, there are winners (e.g., landowners or high-paid rig workers) and losers (e.g., those who can no longer afford the high rents in mining communities and communities dealing with excessive demands on their infrastructure). Moreover, the boom/bust history of the energy economy is that drilling activity usually begins with a wave of drilling and construction in the initial phases, followed by a significant slowdown in jobs as the production phase requires a much smaller number of permanent employees. Indeed Ohio has a long history of energy booms that illustrates that booms too often have few lasting effects. Ohioans need to be aware of this cycle if they are to make prudent decisions and try to gain sustainable gains after the boom has ended. The fundamental problem here is that the time distribution of jobs resulting from a new development is often ignored and it is important. For example it matters whether there are 1,000 jobs distributed as 1,000 for one year and then none, versus 100 additional jobs for 10 consecutive years, or 10 additional jobs for the next 100 years. Yet, 'impact' analysis such as that used by the energy industry typically does not differentiate among these scenarios and the whole topic is usually ignored by the media. Professional economists note that long-term regional economic development requires <u>permanent</u> jobs, and thus independent economists place considerably less weight on the initial construction phase associated with energy development. Policies need to be developed to ensure long-term success.

Natural gas extraction is also associated with potential environmental degradation. Pennsylvania and other areas have reported numerous incidents of water contamination; most notably in Dimock, PA, which was featured in the controversial documentary *Gasland*. Because hydraulic fracturing occurs at levels far below the aquifer level, it is most likely not to blame for contamination, but any contamination is instead likely caused by a casing/tubing failure or other part of the drilling process. Thus, the EPA exempted natural gas extraction using hydraulic fracturing from the Safe Drinking Water Act and Clean Water Act in 2005. However, recognizing increasing concerns over the impact on drinking water and ground water, in 2010 Congress directed the EPA to study the effects of hydraulic fracturing on the environment with results expected by the end of 2012. Until the federal government acts on this issue, state regulations are necessary to ensure natural gas extraction is performed in a safe manner protecting the environment and residents. Yet, coal mining is also associated with high localized environmental costs, indicating that if natural gas mining is not done, there will still be environmental problems that will need to be addressed because more coal mining will be required.

We argue that the focus on whether the industry creates jobs is misguided in assessing its true value and is not how economists typically evaluate the effectiveness of a program or policy. Rather, the focus should be placed on the true costs and benefits of natural gas especially compared to coal (its main substitute in electricity production). *Compared to coal, natural gas is cheaper and emits less carbon and both industries have their own inherent localized environmental costs in their production.* Independent economists would note that neither industry is associated with large numbers of jobs due to their capital-intensive nature. Making a true assessment of the costs and benefits will require qualified independent analysis. Likewise, ensuring that Ohioans benefit long after the energy boom requires innovative planning that unfortunately, most locations that have experienced such booms have failed to do over the last 150 years. These findings also illustrate that Ohio will need to continue to make economic reforms if it is to prosper in the long term because no one industry—in this case energy development—will be its long-term savior.

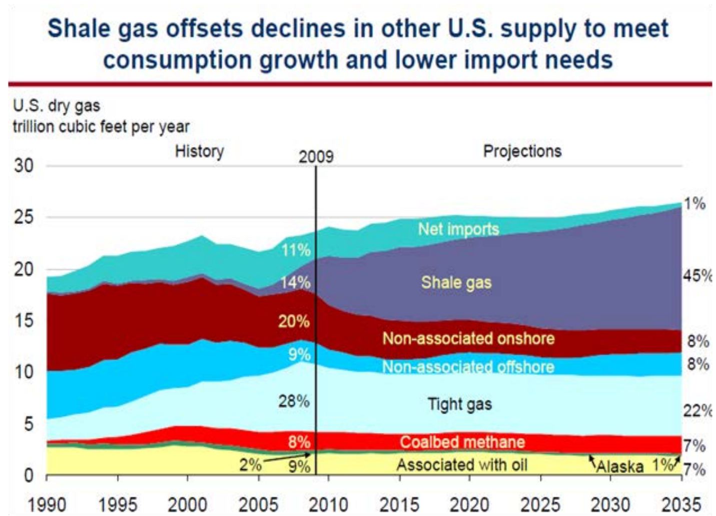
Introduction

With the US economy still struggling to recover from the Great Recession, many are looking for a quick fix to create jobs and generate income. Politicians often turn to the latest economic fad to solve unemployment problems, such as aiming to become the next Silicon Valley or, more recently, the next green energy hub. Employment effects are often overstated to justify various policies rather than having a real conversation about the true benefits and costs of a policy.[1] For example, the job creation benefits of green jobs were optimistically asserted while ignoring the high capital intensity of alternative energy and the displacement effect of jobs no longer needed in the fossil fuels industry, especially coal. In response, the fossil fuels energy industry has now put forward its own solution to unemployment and growing energy demands: natural gas from shale, which also provides its own set of environmental costs and benefits.

In their "Short-Term Energy Outlook," the US Energy Information Administration (EIA) expects that total natural gas consumption will grow by 1.8% in 2011. Despite the increase in consumption, recent increases in natural gas production have met these demands and reduced natural gas imports. Thus, shale gas proponents claim that newly accessible reserves could provide a new level of energy independence for the US. The 2010 EIA "Annual Energy Outlook" found that natural gas production reached its highest levels since 1973 at 21.9 trillion cubic feet (Tcf). This increase in production is mainly attributed to the increase in natural gas extraction from shale resources. From 2009 to 2010 shale gas production more than doubled from 63 billion cubic meters to 137.8 billion cubic meters. This trend in rising natural gas production, especially shale gas production, is likely to continue. Figure 1 below shows the increasing shale gas production the US has experienced, along with future expectations.

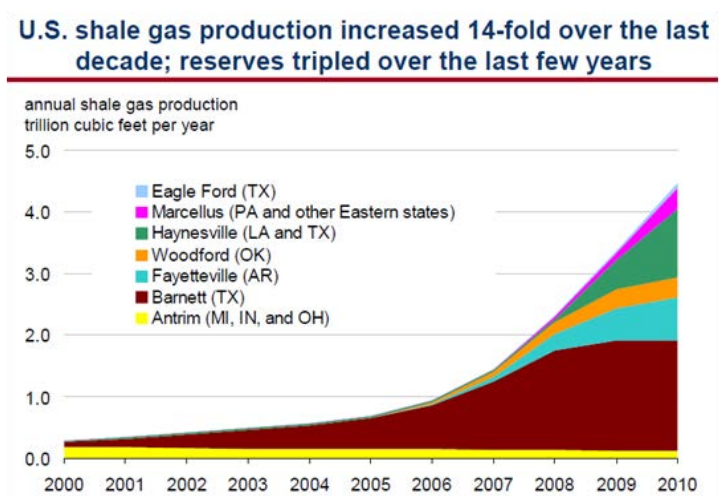
The dramatic increase in shale gas production since 2005 is shown below in Figure 2 separated by the area where shale gas has been developed. Recent technological advancements in a method called hydraulic fracturing, or "fracking", have made extracting natural gas from shale more efficient and cost effective. This has brought natural gas potential to new areas as evidenced by the increased drilling in Pennsylvania. Although still a small percentage compared to Texas, growth in shale gas production in Pennsylvania is growing rapidly and provides a roadmap for how production in Ohio will evolve.

With these innovations, shale gas potential is now growing in neighboring Ohio, which shares the same Marcellus shale with Pennsylvania. Many have already begun to speculate what this could mean in terms of the job benefits to Ohio. An industry-funded study by Kleinhenz & Associates (2011) suggests that new Ohio natural gas production could "create and support" over 200,000 jobs



Source: US EIA Annual Energy Outlook 2011

Figure 1: Shale Gas Prospects



Source: US EIA Annual Energy Outlook 2011

Figure 2: Shale Gas Areas of Production

1. Independent economists have long complained about hyped up numbers from various industry impact reports. For a tongue-in-cheek look see Leach (2011). http://www.theglobeandmail.com/report-on-business/economy/economy-lab/the-economists/who-needs-pipelines-the-oil-bucket-brigade-is-ready/article2268015/

and $14 billion injected into the state economy over the next 4 years (Gearino, 2011).[2] In this manner, Chesapeake Energy CEO Aubrey McClendon stated, "This will be the biggest thing in the state of Ohio since the plow" (Vardon, 2011). Obviously, there is considerable hype surrounding the economic effects of shale oil production

To see if these expectations are realistic, we examine the impacts that natural shale gas has had on Pennsylvania to draw comparisons to Ohio. Many industry funded studies of the economic impacts of the Marcellus shale development in Pennsylvania are consistent with the Kleinhenz & Associates (2011) predictions, which is reasonable in the sense that the early stages of Ohio's development is expected to mimic what happened in Pennsylvania.

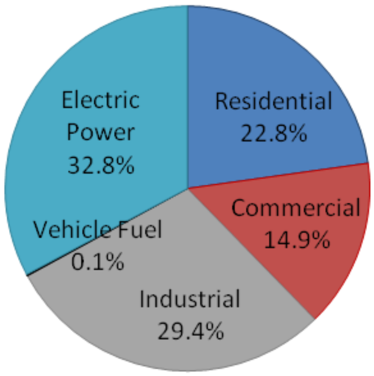
Unlike the industry funded reports, Barth (2010) doubts whether there is any net positive economic impact of drilling in Pennsylvania. She contends that previous industry-funded reports have focused on the benefits while ignoring the costs and risks associated with natural gas extraction. She claims industry funded studies haven't properly accounted for other impacts, including the costs of environmental degradation. Although replacing coal or oil with natural gas can significantly reduce carbon emissions, rising concerns have mounted, most notably in the controversial 2010 documentary *Gasland,* about the potential environmental impacts of natural gas mining on nearby water sources. This has become more of a concern as hydraulic fracturing and natural gas extraction occurs closer to both water sources and population centers in Pennsylvania and Ohio. These concerns have not yet been fully alleviated by the US EPA or the natural gas industry. In 2005, hydraulic fracturing methods were exempted from the Safe Drinking Water Act and Clean Water Act. However, recognizing increasing concerns over the impact on drinking water and ground water, in 2010 Congress directed the U.S. Environmental Protection Agency (EPA) to study the effects of hydraulic fracturing on the environment.

Barth (2010) also argues that previous industry-funded studies have not properly accounted for the impact on infrastructure, property values, and the "displacement" impact pollution can have on other industries such as tourism and fishing. In 2010, tourism employed approximately 400,000 people in Pennsylvania whereas the natural gas industry employed closer to 26,000 (Barth, 2010; BLS). If tourism suffers as a result of the natural gas industry, then a bigger industry could be put at risk from expansion of the natural gas industry, though we note that much of Pennsylvania's tourism industry is not near the mining activity.

Economists have long argued that energy development has limited overall impacts on the economy. There is a longstanding literature that refers to a "natural resources curse" that limits growth from energy development. One reason for the limited effects of energy development is Dutch Disease, which broadly refers to the higher taxes, wages, land rents, and other costs associated with energy development that make other sectors less competitive (including currency appreciation at the national level). These higher costs also reduce the likelihood new businesses will locate in the affected location. Previous research has found evidence of a natural resources curse and Dutch Disease suggesting that a natural resource boom can occur at the cost of other sectors and general long-run economic growth. For example, Papyrakis and Gerlagh (2007) found that US states with a higher degree of reliance on natural resources experience lower economic growth.[3] Kilkenny and Partridge (2009) and James and Aadland (2011) also found evidence of this resource curse at the US county level.

Figure 3 on the next page shows that most natural gas is still used to supply electricity. Thus, with rising electricity demands, increasing natural gas production will lower the need for electricity generation from coal—i.e., we will have more natural gas jobs that are offset by fewer coal jobs. Only 0.1% of natural gas is used as vehicle fuel, which is derived from oil as opposed to coal. Thus, <u>new</u> natural gas will not significantly decrease US reliance on foreign oil unless, as publicly suggested by T. Boone Pickens, the US considers converting more buses, trucks and other vehicles to natural gas. Thus, its effects on "energy security" are rather limited in the foreseeable future as increased electrical demand and the growing reliance on US natural gas will primarily be at the expense of US coal.[4]

2. Kleinhenz & Associates (2011) specify that over 200,000 jobs will be *created* or *supported* but they do not clearly define the difference between "created" and "supported" jobs. In terms of long-term economic development, permanent job creation would be necessary—or does natural gas development create more permanent jobs than what would have happened without the energy development? The latter counterfactual question is not addressed in that report.
3. Dutch Disease refers to natural gas development in the Netherlands in the 1960s and 1970s. The ensuing boom raised costs and appreciated the Dutch currency, rendering Dutch manufacturers less competitive on international markets. After the initial boom settled down, not only were there less employment in the natural gas industry, but Dutch manufactures found it hard to regain their market share on international markets, producing a permanent cost on their economy.
4. The recent expansion of shale development did reduce natural gas imports, but going forward, its main influence will be as a substitute for other sources of electricity, primarily coal.



Source: US EIA

Figure 3: 2010 Natural Gas Consumption by End Use

Even with a significant conversion of vehicles to natural gas, the energy sector as a whole has an employment share that is simply too small to significantly impact the high unemployment rates the US is experiencing. In 2010, the natural gas industry accounted for less than 0.4% of national employment, so even if the sector doubled in size—which is quite a stretch—overall U.S. employment would only be marginally effected (BLS).[5] This is not surprising as natural gas like much of the energy sector (including alternative energy) is quite capital intensive, which reduces the employment effects of natural gas compared to the broader economy.

The pursuit of economic fads is often justified by overpromising jobs while ignoring the displacement effects on other sectors of the economy as well as other costs on the economy. The benefits should be appropriately weighed against the costs, but this requires a better understanding of both the benefits and costs. It should not be based on the overblown hype of either side. Using previous experience from Pennsylvania, we will produce realistic estimates what Ohio should expect from shale gas development over the next four years. We find that although the employment advantages of shale gas have generally been overstated by the industry, there are clear benefits of natural gas production when compared to coal (which has its own environmental risks). The biggest advantages are that natural gas is more cost-effective than coal and can reduce carbon emissions. Coal forms the natural benchmark because in the medium term, natural gas production would displace coal production as the alternative source for electricity.

5. The calculation of total natural gas employees uses the methodology of IHS Global described in more detail in note 7 and we use U.S. Bureau of Labor Statistics Data to derive the employment figures.

Hydraulic Fracturing Overview

Innovations in hydraulic fracturing are the reasons natural gas extraction has recently been developing in the Marcellus shale regions in Pennsylvania and Ohio and now expanding to the Utica shale regions in Ohio. Before investigating the impacts of shale gas development, it is important to understand the hydraulic fracturing method that has made natural gas extraction from shale economically feasible.

Shale is a fine-grained sedimentary rock that can trap petroleum and natural gas well below the surface. Horizontal drilling and hydraulic fracturing now allow the energy industry to extract this trapped gas. Commercial hydraulic fracturing began in 1949, though it took decades of use for innovations to make shale gas extraction more cost effective. Horizontal drilling can cost 3 to 4 times more than conventional drilling, but has the potential of reaching substantially more reserves. Figure 4 from the EIA compares horizontal drilling and hydraulic fracturing to conventional methods of natural gas extraction. Figure 5, further depicts the hydraulic fracturing process.

Horizontal wells and hydraulic fracturing in conjunction with advances in micro-seismic technology aiding both exploration and the drilling process have allowed the energy industry to extract natural gas at greater depths. According to the EPA (Jun., 2010), horizontal wells are drilled to a depth between 8,000 and 10,000 feet. Hydraulic fracturing extracts natural gas from shale using a pressurized injection of fluid composed mostly of water and a small portion of sand and chemical additives that vary by site. This pressure causes the shale to fracture, requiring sand or other propping agents to keep the fissures open and allow gas to escape. Between 15 to 80% of the fluids are recovered from the well before the natural gas is collected. This water called “produced water” can be reused in other wells, but will need to be treated or disposed of at some point.

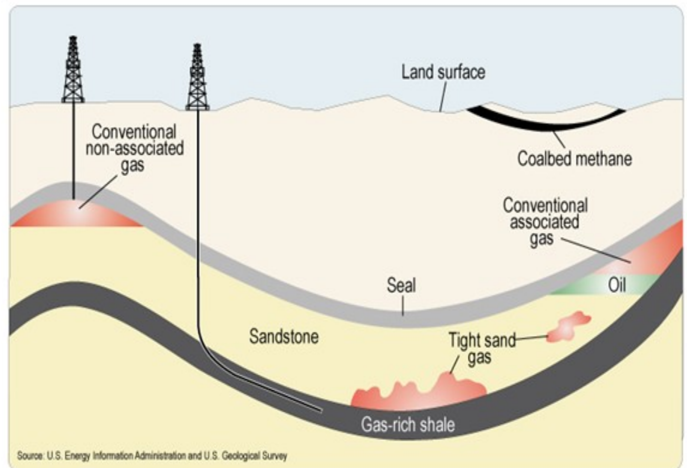
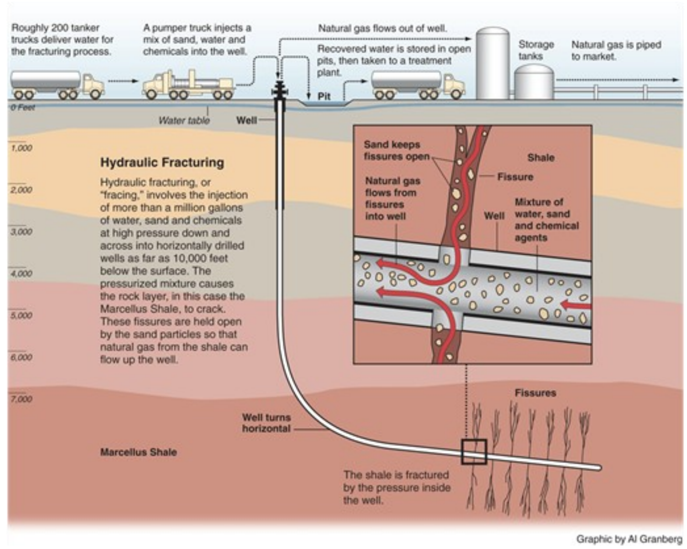


Figure 4: Natural Gas Mining Methods

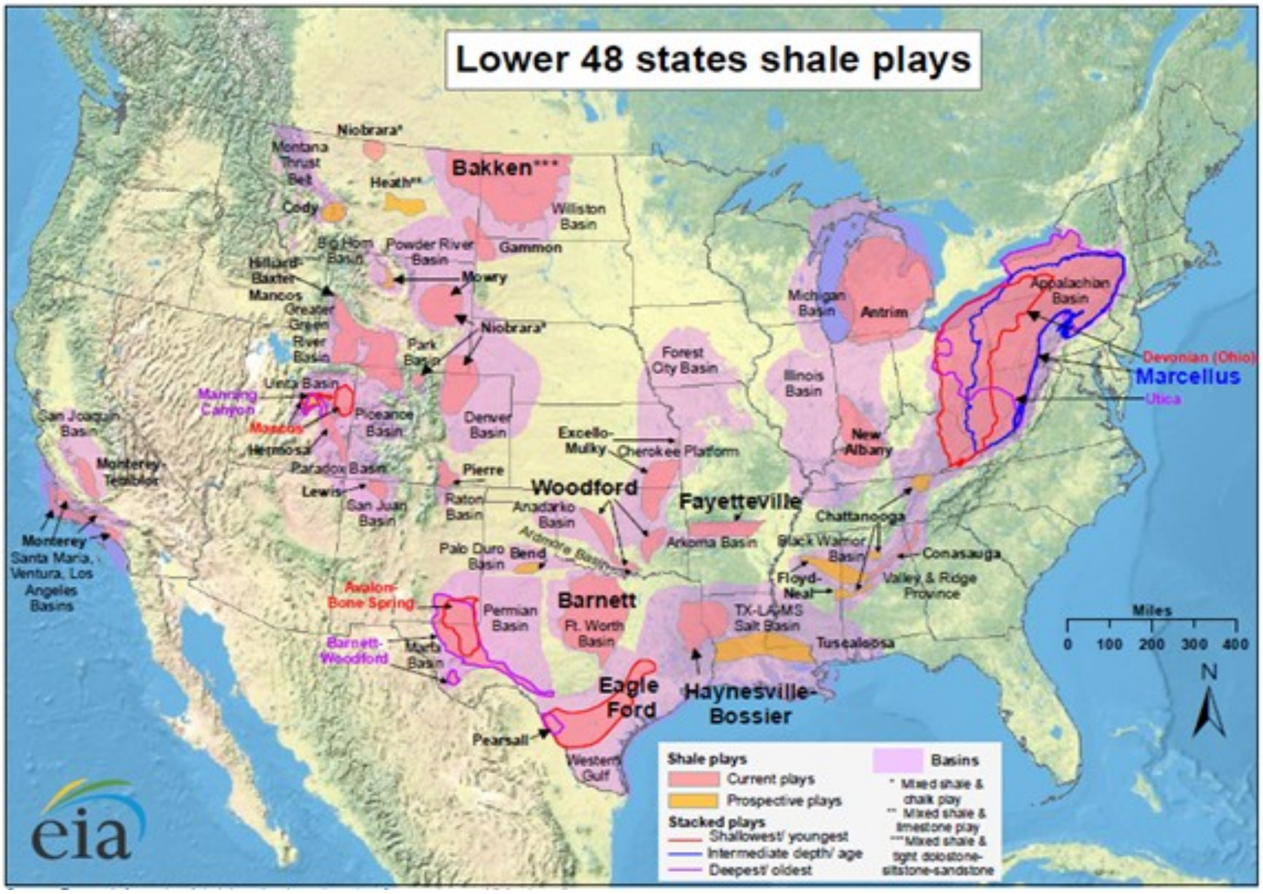


Source: ProPublica

Figure 5: Hydraulic Fracturing

Natural Gas Development in the US:

In the 1980s, the Barnett shale in Texas became the first natural gas producing shale. More than a decade of production from the Barnett shale in Texas has helped improve the hydraulic fracturing process, leading the way for it to be used in other areas such as the Marcellus shale in Pennsylvania and the Utica Shale in Ohio. The Marcellus shale is more than 60 million acres and is significantly larger than the Barnett. The EIA estimates that there are 410 Tcf of recoverable gas in the Marcellus shale alone. Figure 6 on the next page shows the location of US shale plays including the Barnett in Texas and the Marcellus and Utica in Pennsylvania and Ohio. Figure 6 clearly shows that shale natural gas is a national phenomenon that will dramatically alter natural gas availability and pricing nationally. Indeed, EIA data further documents that shale plays are a global phenomenon that will likely reduce world-wide natural gas prices.

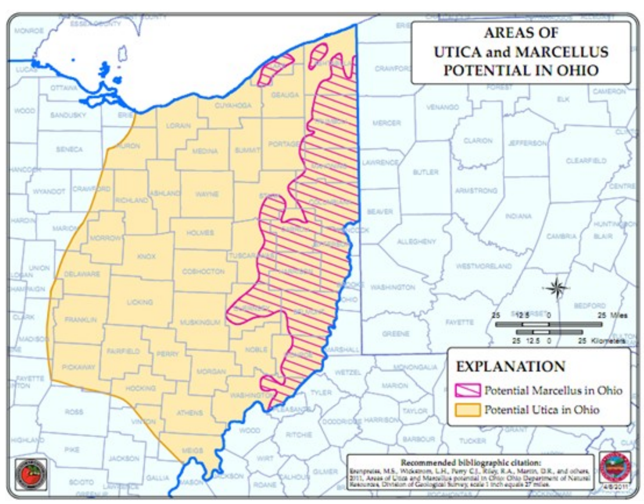


Source: US EIA

Figure 6: US Shale Resources

The large potential of the Marcellus shale, and more recently the Utica shale, has made Pennsylvania and Ohio highly attractive for mining of natural gas reserves. Figure 7 below provides a more detailed look at areas in Ohio that may be directly affected by natural gas resources. In an interview, Douglas Southgate of The Ohio State University's Subsurface Energy Resource Center states that shale resources in Ohio can provide a reliable, cheap, and local source of energy for Ohio. He explains that much of the attention has been on the Marcellus formation, though it is becoming clear that the Utica is more important. In the long term, the latter is expected to supply oil in significant quantities (Dezember and Lefebvre, 2011). It is also an important source of natural gas liquids (NGLs) such as ethane, which is converted into the ethylene used to manufacture a wide array of chemical products (American Chemistry Council, 2011). Thus, Southgate and others argue that shale deposits in and around Ohio are an important source of various hydrocarbons, not just the methane used to heat homes, generate electricity, and so forth.

Ohio shale development is just beginning. Figure 8 on the next page shows specific Marcellus and Utica well activity in Ohio from 2006 through August, 2011. It was recently reported that Chesapeake Energy has its first 4 active Utica shale wells in Ohio producing between 3 and 9.5 million cubic

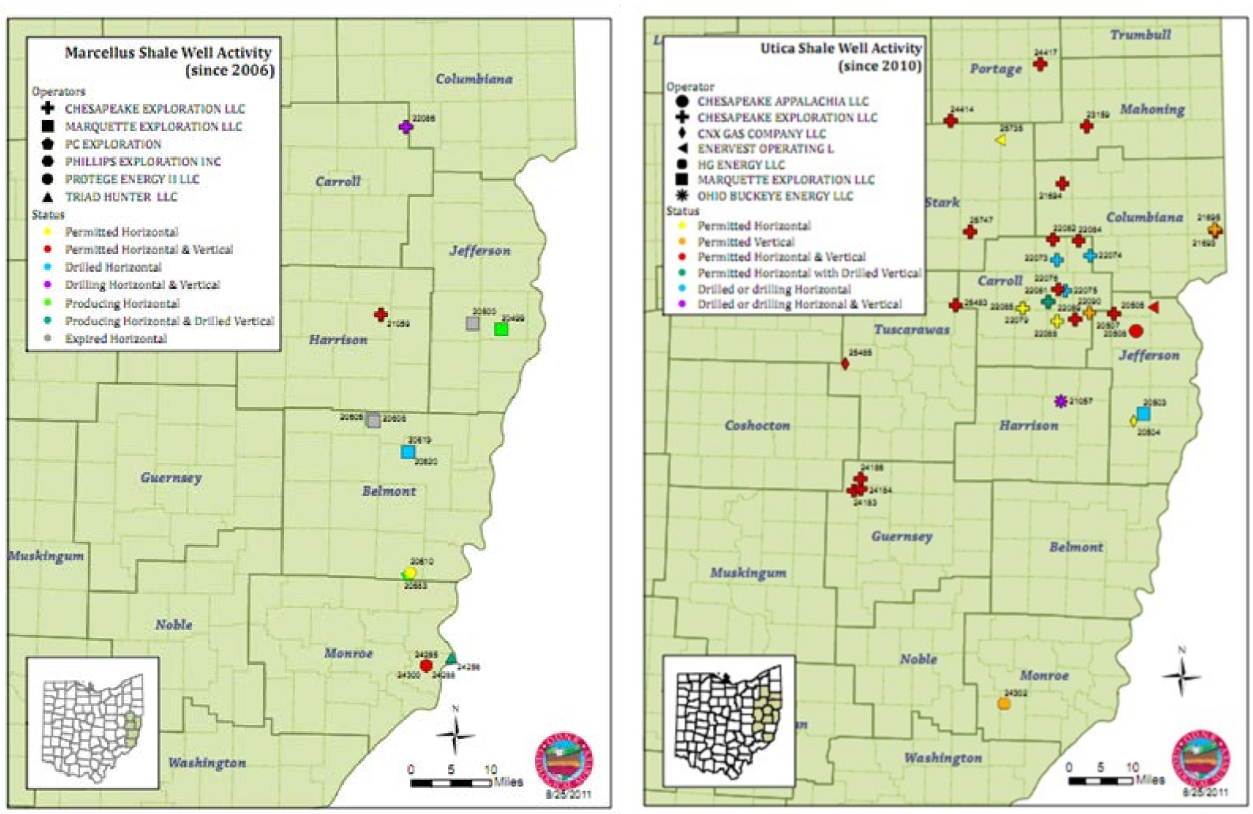


Source: ODNR

Figure 7: Ohio Shale Resources

feet of natural gas per day (Gearnino, 2011). A conventional well might produce between 100,000 and 500,000 cubic feet per day, but the Marcellus and Utica shale wells are expected to produce between 2 to 10 million cubic feet of natural gas per day. Chesapeake plans to increase the number of wells to 20 by the end of 2013.

Although shale development has already begun in Ohio, it is still nascent compared to Pennsylvania. The projected impacts on Ohio are still being debated. For example, Kleinhenz & Associates (2011) projected natural gas development in Ohio would lead to 200,000 jobs and $14 billion in spending. Much of their analysis uses assumptions derived from recent Pennsylvania impact studies such as Considine et al. (2009; 2010; 2011). Kleinhenz & Associates (2011) projected that 4,000 wells will be drilled in Ohio by 2015. Overall, they produced economic results that are similar to the industry-funded estimates for Pennsylvania.



Source: ODNR (Aug, 2011)

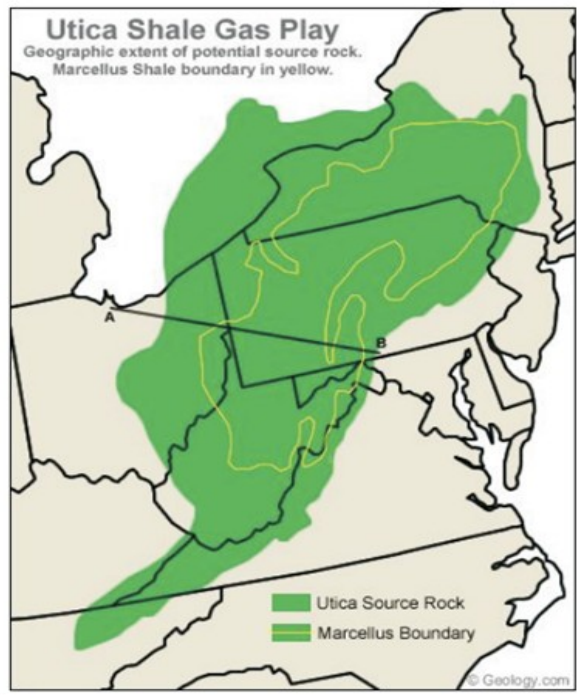
Figure 8: Marcellus and Utica Well Activity in Ohio

Economic Expectations

Pennsylvania is a particularly good gauge to predict what the impacts of shale gas will be on Ohio because they share much of the same natural resources. They are also very proximate and have similar economic structures. Figure 9 shows the Marcellus and Utica shale running through both states. Besides being neighbors, Pennsylvania and Ohio are the 6th and 7th most populous states. For both states, the shale resources are mainly located in rural areas, though there are larger population centers that are affected.

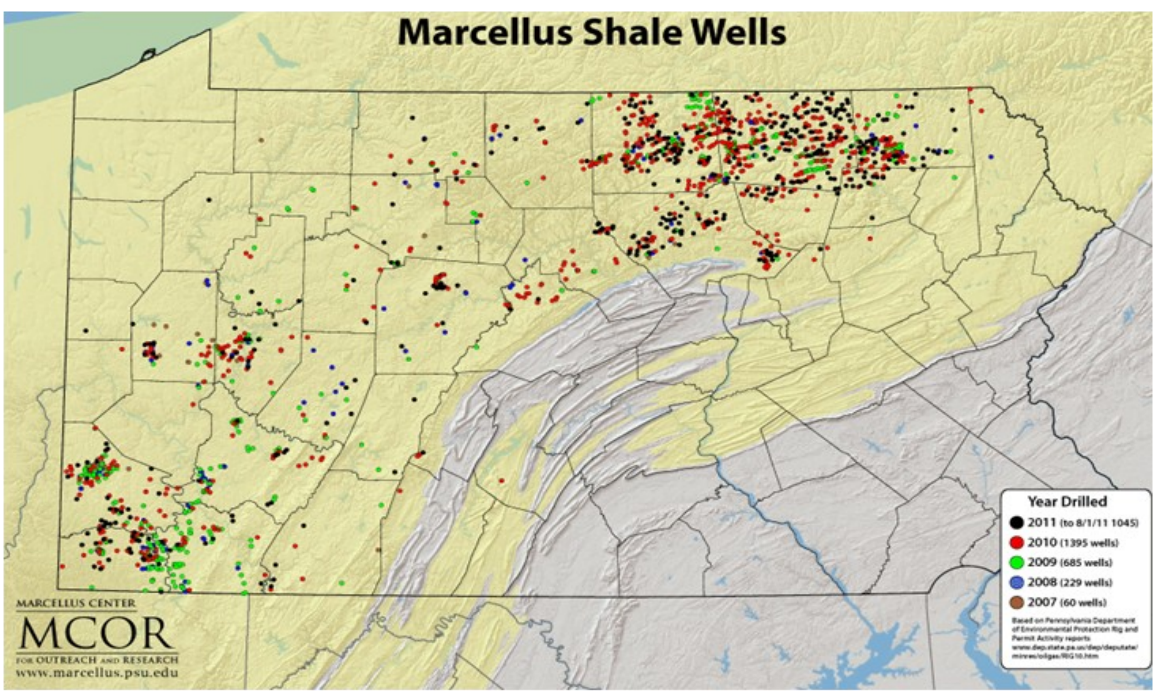
In 2005, the first well in the Marcellus shale in Pennsylvania began producing natural gas. Since then, most of the wells have been located in the northeast and southwest in Pennsylvania. Figure 10 shows the location of wells across the state by year. The number of shale wells drilled grew from 60 in 2007 to 1,395 in 2010. Considine (2010) finds that 36% of the 229 wells drilled in 2008 were horizontal and that percentage is expected to rise.

As the number of wells drilled dramatically increased, so did natural gas production in Pennsylvania, especially in the northeast region. Figure 11 on the next page shows the notable increase in production.



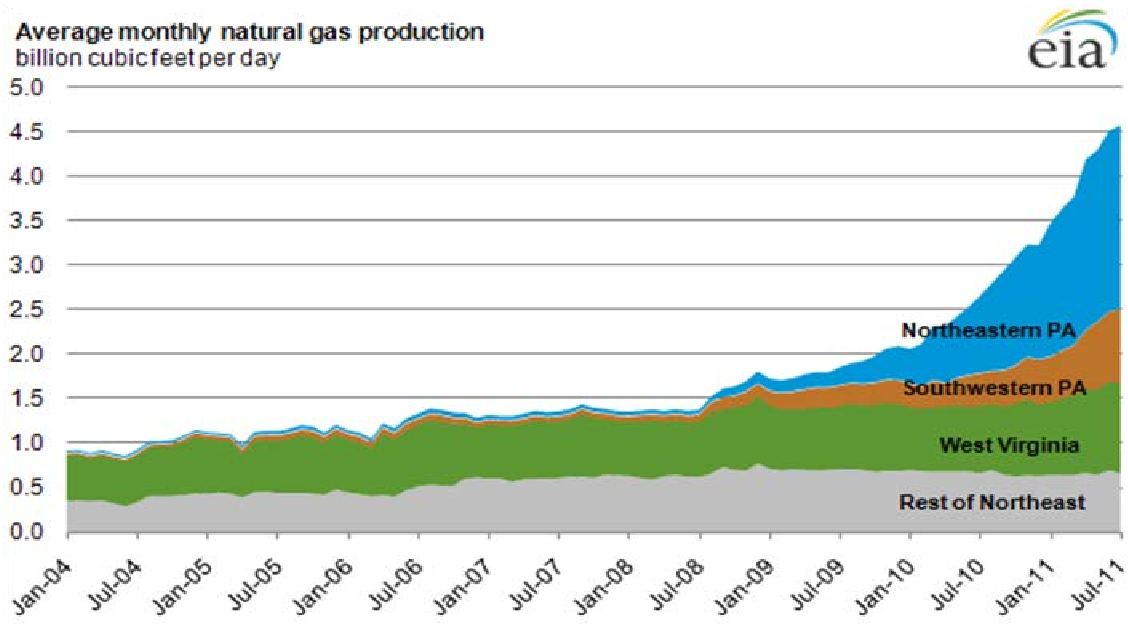
Source: Ohio EPA

Figure 9: Marcellus and Utica Shale Plays



Source: PSU

Figure 10: Marcellus Shale development 2007-2011



Source: US EIA

Figure 11: Northeast Natural Gas Production

Pennsylvania Natural Gas Employment:

Studies of natural gas's role in national and regional economies typically use impact studies (though this is not considered best practice for evaluating economic effects). Impact studies, such as the ones we describe, typically estimate three types of employment effects: (1) direct effects of the jobs directly employed in the activity (in this case natural gas mining); (2) indirect effects that would include inputs to the direct activity (such as pipeline construction); and (3) induced effects due to the added household income (e.g., workers purchasing items in the local economy) (see IMPLAN.com for more details). Summing across the three categories, if done correctly, would produce the total number of jobs "supported" by the industry (not new jobs created). As we describe below, estimating the number of new jobs created would need to assess what would have happened in the absence of natural gas mining—i.e., develop the counterfactual—which is not done in standard impact analysis.

One source of confusion is that impact studies do not produce continuous employment numbers. If an impact study says there are 200,000 jobs, this does not mean 200,000 workers are continuously employed on a permanent basis. For example, there are workers who do site preparation. Then there is another group who do the drilling followed by another group who maintains the well when it is in production. Finally, there is an entirely different group doing pipeline construction, and so on. So, while the public is likely more interested in continuous ongoing employment effects, impact studies are producing total numbers of supported jobs that occur in a more piecemeal fashion.

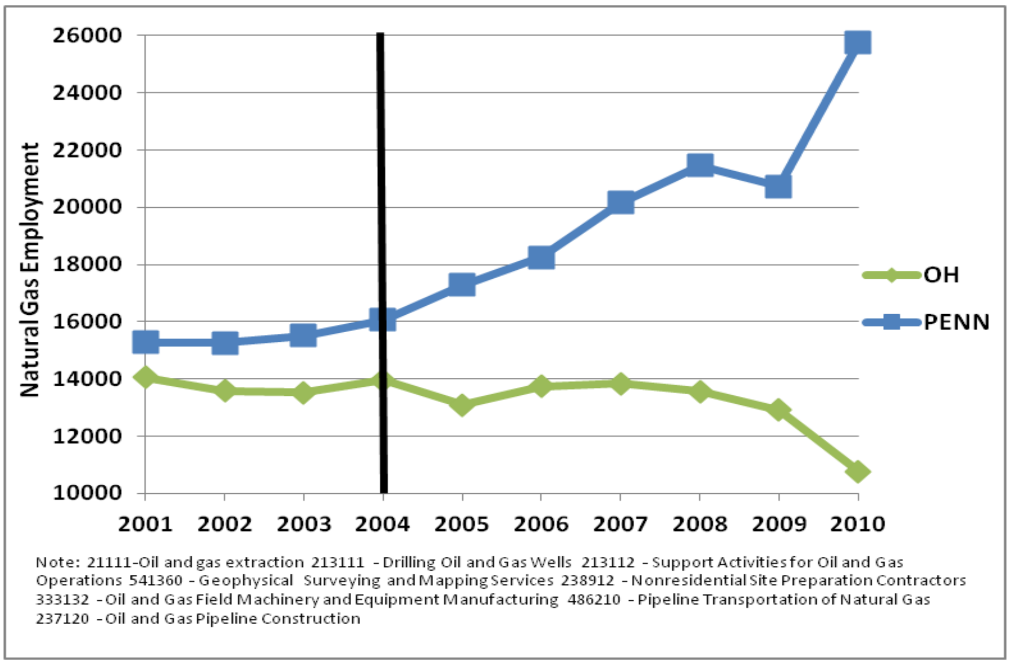
Impact analysis is usually based on an old input-output technology that is typically not used today by economists to estimate actual economic effects. Impact studies do not include various displacement effects and do not reflect the true counterfactual of comparing what would have happened without natural gas drilling. For example, oil and natural gas drilling would lead to higher local wages and land costs, which reduce employment that would have occurred elsewhere in the economy. Likewise, the environmental effects may reduce activity in the tourism sector and other residents may not want to live near such degrading activity. Finally, greater natural gas employment means that there are fewer jobs in coal that would have occurred without the increase in natural gas employment. As described below, best practice economics uses other approaches that try to adjust for displacement effects to derive more accurate estimates of actual effects (see Irwin et al. (2010) for a discussion of the weaknesses of impact studies).

Figure 12 on the next page shows the direct and much of the indirect employment in natural gas and other related sectors in Ohio and Pennsylvania.[6]

6. For the direct effect of natural gas mining, we also include some indirect suppliers that are related to natural gas drilling, which overstates the direct effects. However, not all of the indirect industries are included in Figure 12. When we use a multiplier below, because we already include some indirect effects, we would overstate the total number of supported jobs for the industry.

Since some of the sectors reported in Figure 12 include other sectors—primarily oil—we assume that all of the gain in Pennsylvania employment is due to new natural gas production. Also, we do not include “energy related” sectors in Figure 12 if they showed a large decrease in employment because we believe that would understate the importance of new natural gas production in Pennsylvania (those declines would likely be due to other factors). Thus, if anything, we believe that any measurement “errors” would work to overstate the importance of new gas production employment.[7] From Figure 12, with these assumptions, we assume that from 2004-2010, there was a gain of about 10,000 direct and indirect jobs in the natural gas industry in Pennsylvania.

The typical multiplier would take direct employment and multiply it by the multiplier to arrive at the total effects, including indirect and induced effects. Since the 10,000 number derived above includes some of indirect effects such as pipeline construction, using the standard multiplier would likely lead to an overstatement of the total employment effects of new production. Nonetheless, assuming the standard multiplier of 2 (which is on the high end), the natural gas industries would still have led to about 20,000 direct, indirect, and induced jobs from 2004 to 2010 in Pennsylvania, though this ignores employment losses in other sectors displaced by natural gas.[8] By comparison, Considine et al.’s (2011) industry funded study suggested that natural gas was associated with 140,000 Pennsylvania jobs during 2010.



Source: BLS

Figure 12: Ohio and Pennsylvania Natural Gas Employment[9]

7. IHS Global Insight (2009) notes that employment in these sectors also includes employment in the oil sector and other sectors (not just natural gas). They calculate some national estimates of natural gas’s share of overall employment in each sector. For example, they estimate natural gas’s employment share for the following industries as follows: (1) 2111-Oil and gas extraction, 213111 - Drilling Oil and Gas Wells, and 213112 - Support Activities for Oil and Gas was 74% in 2008; (2) 237120 - Oil and Gas Pipeline Construction was 68% in 2008; (3) 333132 - Oil and Gas Field Machinery and Equipment Manufacturing was 65% in 2008 and (4) 238912 - Nonresidential Site Preparation Contractors was 16% in 2008). We could have used IHS Global Insight’s shares in our calculations, but we believe this would **understate** the increase in the size of the natural gas sector in Pennsylvania because some of the gains would be attributed to other sectors.
8. Academic economists generally use a multiplier of 2 as an upper bound multiplier. For example, Stabler and Olfert (2002) describe a range of employment multipliers in the 1.1 to 1.5 range. Hughes (2003) describes that *output* multipliers above 2.5 are likely very questionable. Likewise, Kelsey et al. (2009) found an output multiplier for natural gas in Pennsylvania to be in the 1.86 to 1.90 range, further showing that our 2.0 multiplier is reasonable. Indeed, as the economy becomes more global, fewer employment gains are on-shore or local, which would reduce employment multiplier effects. Likewise, with outsourcing and increasingly fragmented supply chains, firms are further shifting their purchases outside the firm, which further reduces the amount purchased locally. Further, keep in mind that the energy sector is highly capital intensive which would work to reduce the employment effects and increase the output effects in a multiplier. Thus, we believe our use of an employment multiplier of 2 would be viewed as “generous” by independent academic economists.
9. The direct effects would commonly include the drilling and extraction activities while indirect effects would normally include inputs such as pipeline construction and field equipment manufacturing. Hence, this is why we state that we are already including some of the key inputs as direct employment in Figure 12.

We believe that independent and academic economists in regional and urban economics would view our 20,000 employment estimate as reasonable and some may view it on the high end of actual job creation.[10] For example, Barth (2010) notes that other studies found a multiplier for oil and gas as low as 1.4. She also notes that in similar input-output studies, other industries were found to have higher multipliers than oil and gas, with agriculture having one of the highest multipliers. If shale development adversely effects employment in (say) coal mining, agriculture, and tourism, then those numbers should be subtracted from these numbers to derive the actual employment effects (including any multiplier effects in those sectors). To be sure, we only calculate an impact style estimate to give a feel of the overestimated effects produced by industry consultants (and others who produce impact studies). There are much better approaches than impact studies to calculate actual effects, which we describe below.

One other issue is that proponents of natural gas expansion in Ohio often claim that lower natural gas prices will provide a major stimulus to overall employment, especially in manufacturing. While we will not assess whether natural gas prices are a sufficient share of a typical firm's cost structure to make a tangible difference, we do note that there are reasons to be skeptical of those claims (though we hope we are wrong). Foremost, to make a difference on Ohio's relative competitive edge compared to the rest of the United States and the rest of the world, it would have to be an event that helps Ohio's businesses much more than in the rest of the world. However, as we note in the discussion surrounding Figure 6, shale natural gas is a global phenomenon, meaning that falling natural gas prices will benefit a significant share of Ohio's global competitors. Thus, there is no "edge" given to Ohio's businesses that would make them tangibly more competitive than their national and international competitors.

Economists typically subject their forecasts to "smell tests" by making comparisons to similar events. In our case, comparing energy development around North Dakota's Bakken shale formation in the far northwestern part of the state is good benchmark to assess whether our 20,000 job forecast for Ohio makes sense. Specifically, development of North Dakota's Bakken shale region has been about the same magnitude as the energy development in Pennsylvania and should produce somewhat comparable job effects on both states.[11] During the October 2007-October 2011 period (or a four year period that corresponds to Kleinhenz & Associates' Ohio study), the entire state of North Dakota added about 39,000 jobs. It is highly unlikely that this is all due to energy as high commodity prices (for example) have supported North Dakota's relatively large farm economy. Further, we would expect that the Bismarck metropolitan area (which is relatively close to the mining activity) to be more impacted by the energy boom, while the Fargo and Grand Forks metropolitan areas that are hundreds of miles away on the Minnesota border to be considerably less affected. In this comparison, Bismarck added 4,600 jobs during this four-year period, while Fargo and Grand Forks metropolitan areas respectively added 4,400 and 1,600 jobs. These figures strongly suggest that North Dakota's relative prosperity is more widespread than just an energy boom in the Bakken region. So, even if all 39,000 North Dakota jobs were due to energy (which we have already shown is highly unlikely), this would be a far cry short of the 200,000 jobs that have been forecasted for Pennsylvania and Ohio despite the comparable size of the three states' energy booms.[12] Thus, our forecast of 20,000 jobs over the next four years is further supported as a reasonable forecast based on the North Dakota experience.

Although Pennsylvania's natural gas employment gains are impressive, they still represent just a small share of total state employment. From 2004 to 2010, the employment share of oil and natural gas related sectors shown in Figure 12 increased from 0.30% to 0.48% (see Figure 13). This small employment share is simply not enough to have a significant effect on total jobs and on unemployment for the state.[13] Despite the significant increase in natural gas jobs from 2009 to 2010,

10. For example, there are many factors affecting the actual employment number. If there are workers from out of state, Ohio's employment number would be lower. Conversely, if more landowners are in state compared to Pennsylvania, that would increase the employment number. Other factors are harder to predict such as mining's effect on agriculture and timber.

11. U.S. Bureau of Labor Statistics Data (Current Employment Statistics) suggests that between October 2007 and October 2011, mining employment (which is due to the direct energy production) increased by about 12,000 in both states. The other employment numbers referred to here are from the same source.

12. U.S. Bureau of Labor Statistics Data shows that North Dakota had an October 2011 unemployment rate of 3.5%, which seems quite low compared to the 9.0% national rate. However, North Dakota always has very low unemployment rates due to long-term structural reasons (Partridge and Rickman, 1997a, 1997b). For example, it was an even lower 3.0% in October 2001, well before the energy and commodity price boom of recent years, illustrating that the energy boom is only a partial reason for North Dakota's current low unemployment rate.

13. To give a further feel for the size of the natural gas sector in Pennsylvania, Barth (2010) finds that in January 2010 there were 48,777 Walmart employees in Pennsylvania (almost double that of the natural gas industry broadly defined) and approximately 400,000 jobs in the tourism industry.

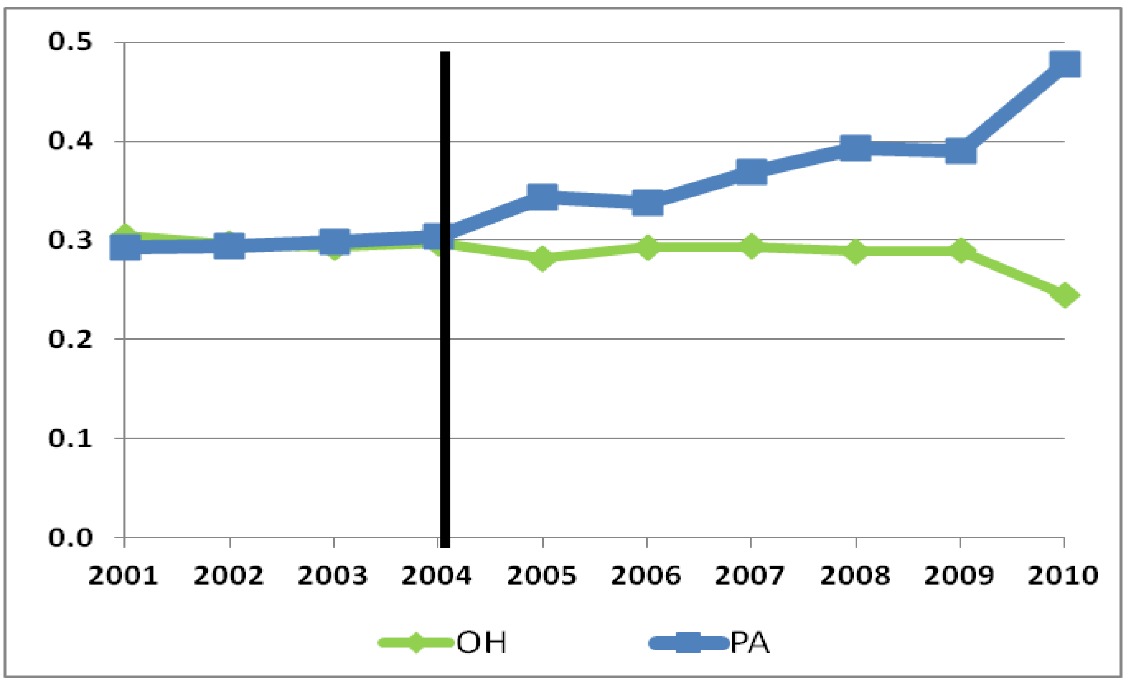
Pennsylvania's unemployment rate still increased from 8.0% to 8.7% during this time (BLS: U.S. Department of Labor, Bureau of Labor Statistics). At most, natural gas employment effects would be localized. Conversely, Ohio's unemployment rate remained unchanged at 10.1% from 2009 to 2010 (BLS) despite a loss in the energy sector jobs in Figure 12, illustrating that natural gas employment is not driving either state's economy.

Concerns with the Economic Impact Studies of Natural Gas Development:

Impact studies are typically associated with overstatements of the employment effects of new development. For example, the Considine et al. (2011) study appears to include indirect and induced jobs before applying the multiplier effect, which double-counts effects and blows up the estimated effects. Direct jobs should include those jobs directly associated with drilling the wells and extracting the natural gas. Indirect jobs include the jobs associated with various inputs required by the industry such as pipelines. Induced jobs should include those jobs and services required by the workers such as restaurants and entertainment.[14] The final two categories should be the outcome of the multiplier process.

Second, Considine et al. assumes that 95% of natural gas industry spending will occur in Pennsylvania. Kleinhenz & Associates assumes a slightly more conservative 90% of all spending will be spent in Ohio. In global economies in which state economies are integrated with national and international economies, such assumptions would not be credible for independent economists. Moreover, because the industry is relatively new and undeveloped, more of the inputs would be brought in from outside of the state, e.g., from Texas.[15]

There are other problems with impact studies because, in reality, more of the money leaks out. For example, Kelsey et al. (2011) found 37% of the Marcellus employment has gone to non-Pennsylvania residents and that landowners save or invest approximately 55% of the money they make from royalties/lease payments rather than spending it in the local economy. They use these



Source: BLS

Figure 13: Ohio and Pennsylvania Natural Gas Employment Shares of Total State Employment

14. Examples of jobs that should not be categorized as direct to natural gas mining are Finance & Insurance, Educational Services, Health, Arts & Entertainment, Hotel & Food Services, etc. By including these jobs as direct jobs, Considine et al. is essentially double counting the employment effects. While we do not have Considine et al.'s programming we believe one source of the double counting derives from how household spending from lease payments/royalties are treated. Even using the job estimates of Considine et al., it is still not a significant portion of the total employment in Pennsylvania.
15. We believe a more reasonable approach would have been to use the default state spending shares from the IMPLAN software (i.e., Considine et al. overruled IMPLAN's default numbers and incorporated 95%). In the absence of detailed and regional I-O data, other shortcuts have been used such as payroll to sales ratios (Oakland et al., 1971; Rioux and Schofield, 1990; Wilson, 1977) or Value-added to gross outlays by industry (Stabler and Olfert, 1994).

	Population 2005	Per Capita Income 2005	Employment Growth Rate 2001-2005	Employment Growth Rate 2005-2009	Income Growth Rate 2001-2005	Income Growth Rate 2005-2009
Non-Drilling Counties	255,508	$32,187	5.3%	-0.4%	12.6%	13.6%
Drilling Counties	124,928	$27,450	1.4%	-0.6%	12.8%	18.2%

Source: BEA

Table 1: Pennsylvania County Descriptive Statistics

more realistic findings to develop a better estimate of the economic impacts of shale development in Pennsylvania. Using IMPLAN, Kelsey et al. (2011) find that in 2009, Marcellus shale development economic impact was over 23,000 jobs and more than $3.1 billion. Our estimate of 20,000 jobs then closely corresponds to Kelsey et al.'s estimates (2011).

Finding Counterfactuals to Assess Growth:

The key problem with impact studies is that they do not estimate the actual number of jobs created by mining because of all of the displacement effects. They are not the true counterfactual and economists have not viewed them as best practice for decades (Irwin et al., 2010). Economists have developed other more credible approaches in developing a counterfactual, such as difference in difference approaches. One of these approaches is to match drilling counties to non-drilling counties that otherwise would have had similar employment patterns if there was no drilling. Thus, the goal is to find counties that would have looked similar to the drilling counties in the absence of drilling. We describe this approach below.

Although natural gas employment does not seem to have had a significant impact on the state as a whole, it may still have a sizeable impact on the specific counties, many of them rural. Table 1 presents data for Pennsylvania counties before and after drilling. Table 1 shows that before 2005, drilling counties are notably struggling more than non-drilling counties. Drilling counties on average are less populated, more rural, have lower per capita income and less employment growth. Natural gas leases also provide an additional source of income for landowners. Landowners that choose to lease their land to natural gas companies generally receive an upfront payment per acre and royalties on the gas produced from the well. Although the payout varies, it can be quite sizeable. From Table 2, it seems natural gas development is positively related to per capita income growth rates for drilling counties.

Table 1 highlights the fact that drilling counties on average look very different than most non-drilling counties. Thus, we look specifically at 3 significant high-drilling counties in the northeast (Tioga, Bradford, and Susquehanna) and 3 in the southwest (Washington, Greene, and Fayette).[16] We then match each of these two sets of mining counties to similar non-mining counties (as of 2009) based on population and similar employment and income dynamics *before* 2005 and the advent of shale drilling.[17] Figure 14 shows the mining and non-mining counties that were chosen. Figure 14 shows that the matches are divided into the Northeast quadrant of the state and the southern part of the state. The appendix provides additional graphs directly comparing each drilling county with its matched

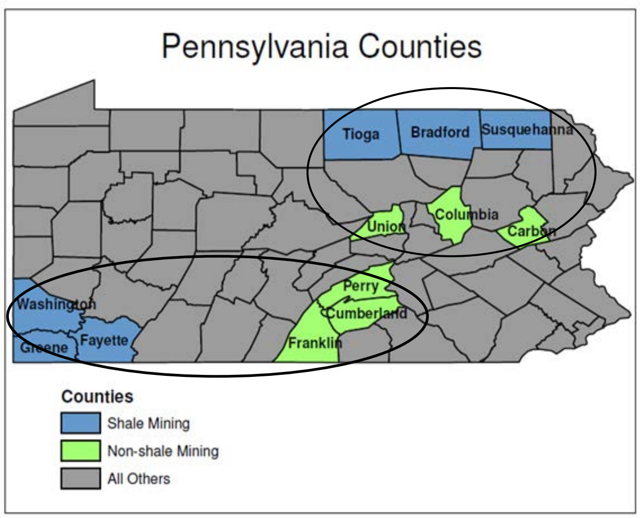


Figure 14: 2009 Matched Drilling and Non-drilling Counties

16. Drilling counties were matched to non-drilling counties on the basis of population and general urbanization as well as region (either north or south).
17. Matching studies can employ other mathematical approaches to finding matches. As will be apparent, our choice of non-drilling counties will appear to be good matches.

non-drilling county.

Using BEA employment and income data, the shale mining counties are compared to the non-mining counties with 2004 marking the point immediately before drilling activities began. One of the key features of the employment and income data is that both mining and non-mining counties are on similar growth paths prior to drilling, suggesting there they are good comparisons (see Figures 15-18 in the next pages). Figure 15 suggests that mining counties may have had faster job growth in the Southern region, but Figure 16 shows that the opposite applies in the Northeastern region. Overall, there are no clear employment effects for heavily drilled counties. We are not saying there are no drilling employment effects, but that they are not large enough to be detected in this commonly used matching approach. One reason may be that many of the new jobs may go to people outside the state who have previous experience in natural gas extraction.[18] Conversely, the positive impacts on incomes are more clear. Figures 17 and 18 show the per capita income impact of natural gas drilling appears to be positive in both Southern and Northeastern regions. While the effects may differ in longer-run periods, our four year window conforms to Kleinhenz & Associates' four year forecast for Ohio.

To be sure, there are many things happening in these county economies, but such efforts to form the true counterfactual are more in line with best economic practice than the impact studies that are often used by economic consultants. In particular, one especially appealing feature is that our approach is based on actual employment and income data and not based on the assumptions of computer software.

For further comprehensive analysis to appraise whether our previous matched results are correct, we now perform a statistical analysis on all counties within Pennsylvania. To control for county-specific effects, we use a difference-in-difference approach to find the impact of drilling on the change in employment after drilling compared to the change in employment before drilling. Details of the difference-in-difference methodology are provided in the appendix, but essentially we are examining whether having more natural gas wells is associated with more job and income growth, but this time we are considering all Pennsylvania counties. This approach accounts for the fact that drilling and non-drilling counties may have systematic differences (fixed effects) for a variety of reasons - and we are adjusting for these differences. Table 2 shows that the number of wells drilled since 2005 has no statistically significant effect on employment.[19] Overall, we believe that there have been modest employment effects in drilling counties, but they are not large enough to statistically ascertain (most likely due to some of the offsetting factors we just described). The upshot is decision makers who are interested in the actual job creation effects of natural gas need to take much more seriously the displacement effects throughout the economy.

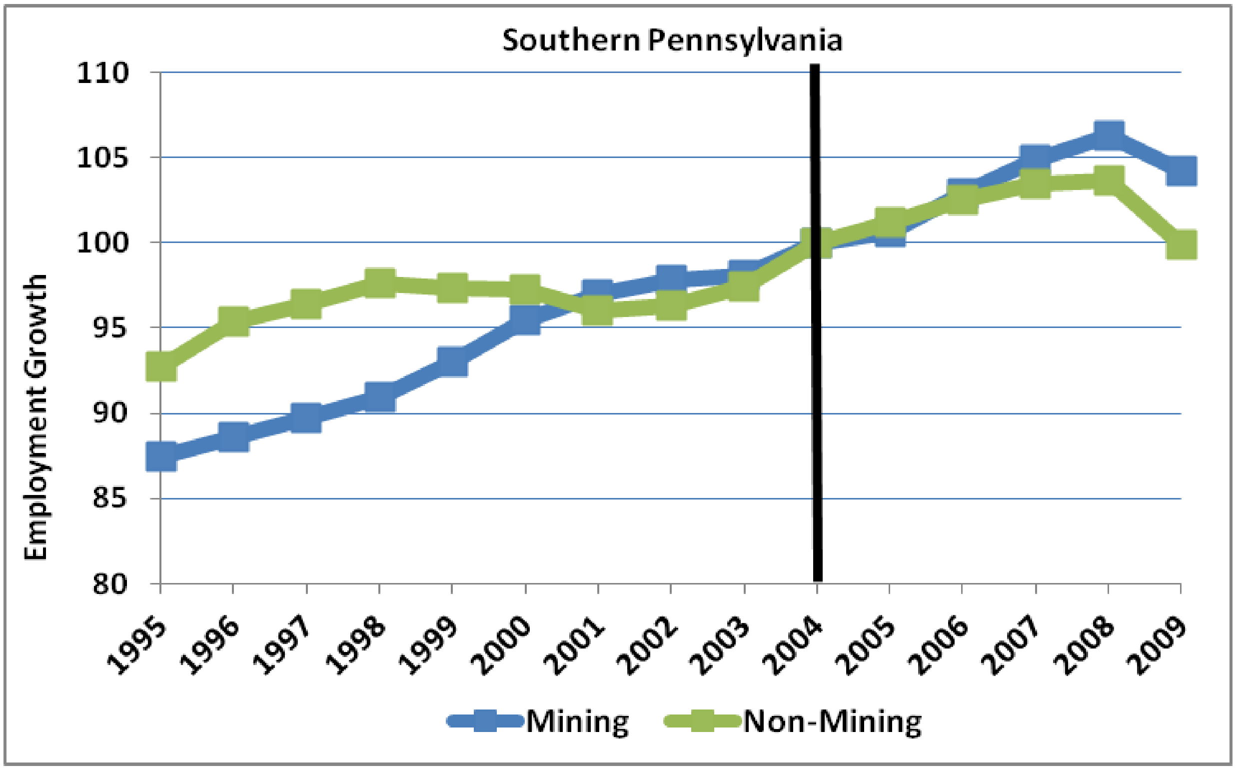
There are many important reasons why we would expect natural gas' impact on employment to be small or insignificant, which explains the findings in Figures 15 and 16 and in Table 2. Besides displacement, one reason is the production technology of natural gas. Like other fossil fuel energy industries, natural gas is rather capital intensive.

	Change in Percent Employment Growth 2005-2009 Compared to 2001-2005	
	Parameter Estimate	t-value
Total Wells 05-09	**1.769E-05**	**1.14**
2001 Log Population	0.023	2.64
2001 Log Per Capita Income	-0.096	-1.55
N	67	
R2	0.118	
Adjusted-R2	0.076	

Source: BEA and Pennsylvania DEP Data. See the appendix for more details.

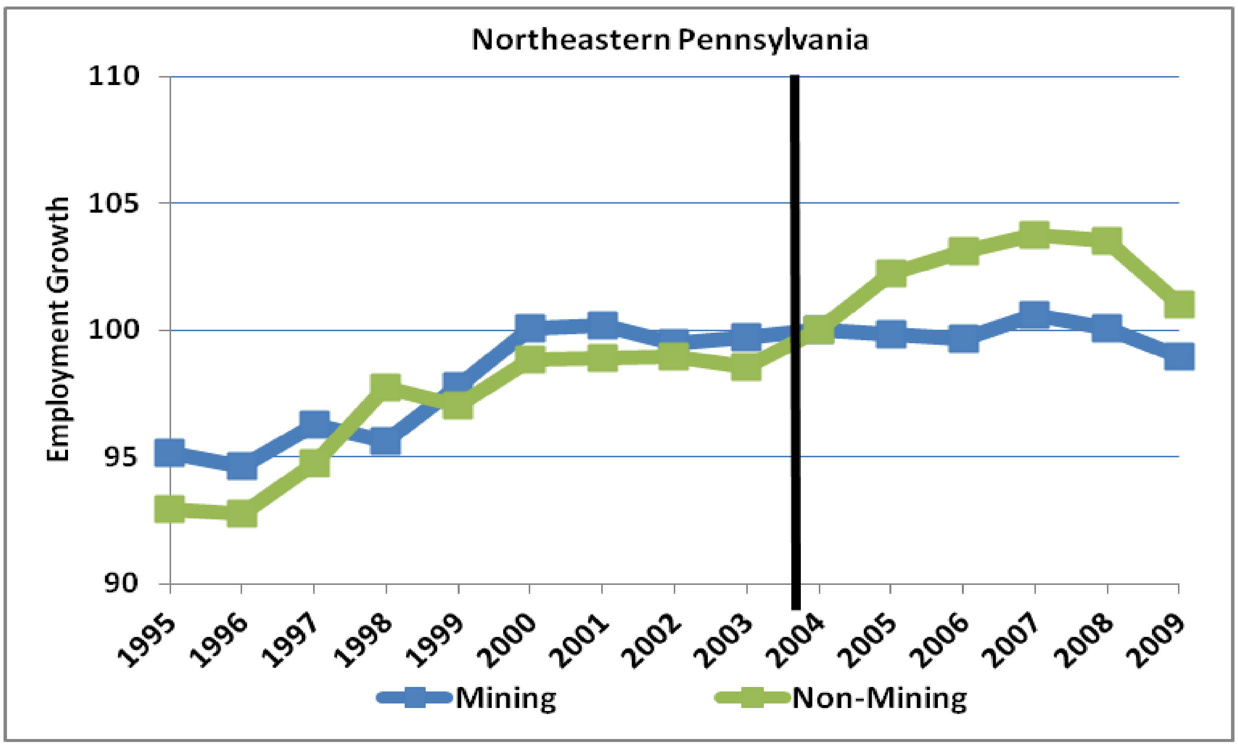
Table 2: Employment Effects of Drilling

18. Pennsylvania and Ohio residents may not have the skills and experience needed to meet the demands of the natural gas industry and royalty/lease monies may not be spent locally. Similarly with natural gas spending, Pennsylvania may not have the services and supply chain the energy industry requires initially. Along with other displacement effects, this may explain the lack of employment response.
19. We also considered that possibility that there are threshold effects (or other nonlinearities) in which drilling does not affect economic growth until a certain number of wells are drilled. We did this by adding a number of wells drilled squared term to the model. This variable's coefficient was negative and statistically insignificant in both the income and employment growth models, suggesting that there are no nonlinear effects. Additionally, these numbers don't account for people switching from part time to full time employment.



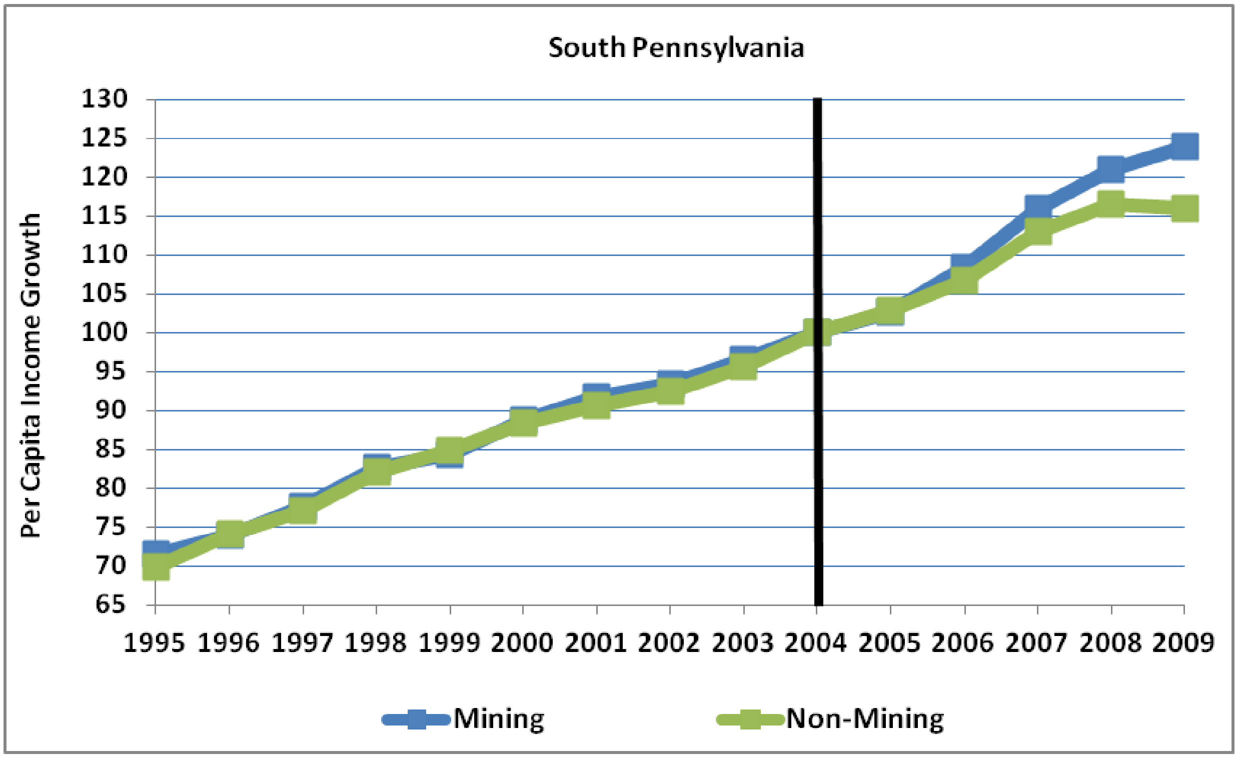
Source: BEA Mining counties (Washington, Greene, and Fayette) Non-mining counties (Perry, Franklin, Cumberland)

Figure 15: Drilling and Non-drilling Employment Comparison (2004=100)



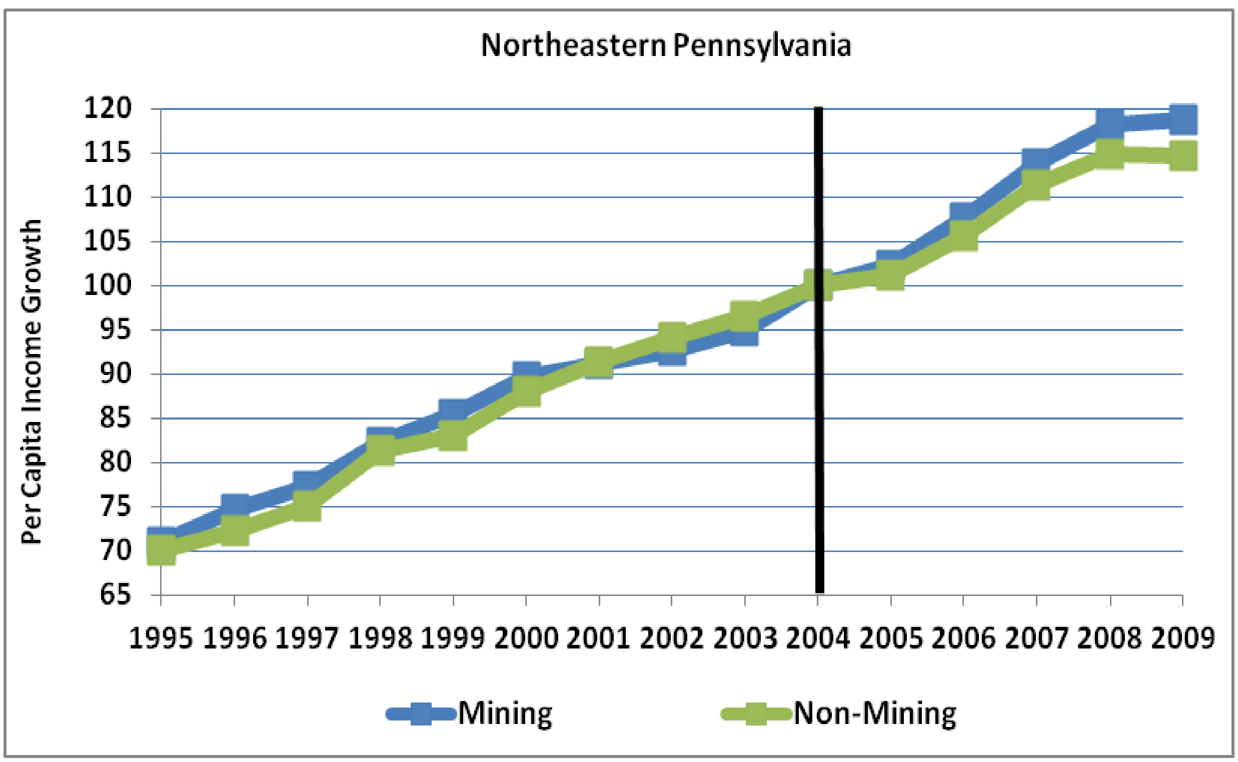
Source: BEA. Mining counties (Tioga, Bradford, and Susquehanna) Non-mining counties (Union, Columbia, Carbon)

Figure 16: Drilling and Non-drilling Employment Comparison (2004=100)



Source: BEA. Mining counties (Washington, Greene, and Fayette) Non-mining counties (Perry, Franklin, Cumberland)

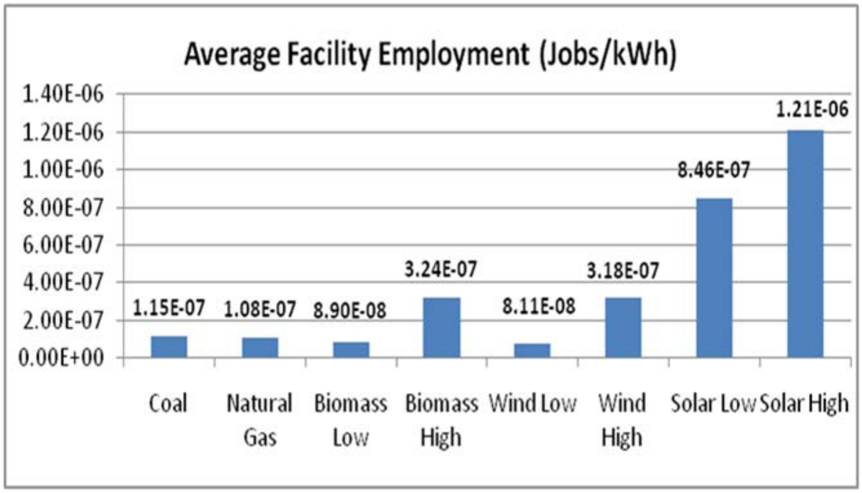
Figure 17: Drilling and Non-drilling Per Capita Income Comparison (2004=100)



Source: BEA. Mining counties (Tioga, Bradford, and Susquehanna) Non-mining counties (Union, Columbia, Carbon)

Figure 18: Drilling and Non-drilling Per Capita Income Comparison (2004=100)

Figure 19 shows the estimated number of jobs required to produce a kWh of electricity. Natural gas actually requires fewer jobs to produce a given amount of electricity than coal. The job requirements for natural gas electricity production are low because it is efficient at producing a kWh. In this case, fewer jobs created is actually a good thing for the overall competitiveness of the economy because that implies low-cost electricity, but it means that natural gas drilling has smaller employment impacts.



Source: Weinstein et al. (2010) chart using data from Kammen et al. (2004)

Figure 19: Jobs Requirements to Produce a kWh by Energy Source

As figure 3 shows, most natural gas resources (32.8%) are used for electricity. When switching from coal to natural gas, there will be significant displacement effects in addition to the effects of natural gas being more productive than coal in producing a kWh. Using the same technique shown in Weinstein et al. (2010), Table 3 shows the approximate employment effects of even large shifts (25% of the kWh produced from coal to kWh generated from natural gas) are rather small. In both cases, there are small employment losses with Ohio having more employment losses due to a higher percentage of electricity being generated from coal.

	Total kWh from Coal 2009	Change in Jobs	Change in Energy Costs (millions)	Change in Emissions (lbs)
Ohio	113,711,997,000	-195	-$491,804	-23,822,663,372
Pennsylvania	105,474,534,000	-181	-$456,177	-22,096,914,873

Source: EIA and Weinstein et al. (2010)

Table 3: Effects of Displacing Coal with Natural Gas

	Change in Percent income Growth	
	Parameter Estimate	t-value
Total Wells 05-09	**2.515E-05**	**2.11**
2001 Log Population	0.084	2.53
2001 Log Employment	-0.086	-2.76
N	67	
R2	0.205	
Adjusted-R2	0.167	

Source: BEA and Pennsylvania DEP Data

Table 4: Income Effects of Drilling

Table 4 shows the regression results for a difference-in-difference for county per-capita income. In this case, the income injected into the economy by the natural gas industry through leases and wages appears to have a significant positive effect on per capita income. These results, along with the employment regression results, verify our previous analysis using matched drilling and non-drilling counties. Drilling seems to have a positive and significant effect on income in drilling counties - but not on employment.

The Benefits and Costs of Natural Gas

Once the realistic expectations of the employment and income effects of shale natural gas development are properly assessed, these impacts can be included when weighing the benefits and costs of shale gas.

The Benefits of Natural Gas:

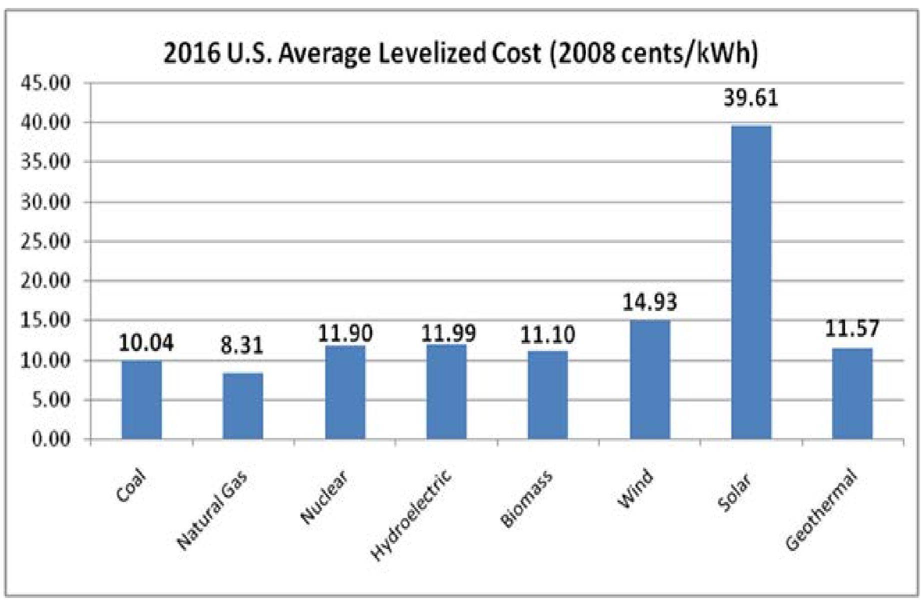
Other than the income effects and modest employment impacts, additional benefits to natural gas include lower energy prices, natural gas imports, and carbon emissions (especially compared to coal). First, Figure 20 below shows the average levelized cost to produce a kWh. As shown in Table 3, natural gas decreases electricity costs for end users. However, if natural gas prices are too low it will be less economical to pursue shale gas.[20]

Pennsylvania and Ohio are also good locations to produce natural gas as there is significant natural gas infrastructure in the area and large population and industry centers that require natural gas as shown in Figure 21 on the next page. This proximity further decreases energy costs by reducing transportation costs.

Increasing domestic sources of natural resources are reducing the demand for foreign gas. The EIA reports that 87% of the natural gas consumed in 2009 was produced domestically. Figure 22 on the next page shows that since 2007, natural gas imports have been declining. However, as already noted, future increases in natural gas production will have very little effect on "energy security" as our largest problem relates to oil imports.

The potential benefits of natural gas have been touted by both the industry and the US EIA. However, the ability to supply the country's energy's needs may have been overstated. In the 2011 Annual Energy Outlook, the EIA estimates that 2,543 Tcf of potential natural gas resources could supply the U.S. for approximately 100 years at the 2010 level of annual consumption. However, this does not account for the increasing trends in consumption. Accounting for the trend in consumption from 1974 to 2010, this estimate falls to 65 years. Using a more recent trend from 1986 to 2010, the estimate falls to 52 years. Despite the significant reserves, natural gas energy strategies still suffer from typical fossil fuels problems such as nonrenewability.

The Environmental Benefits and Costs:

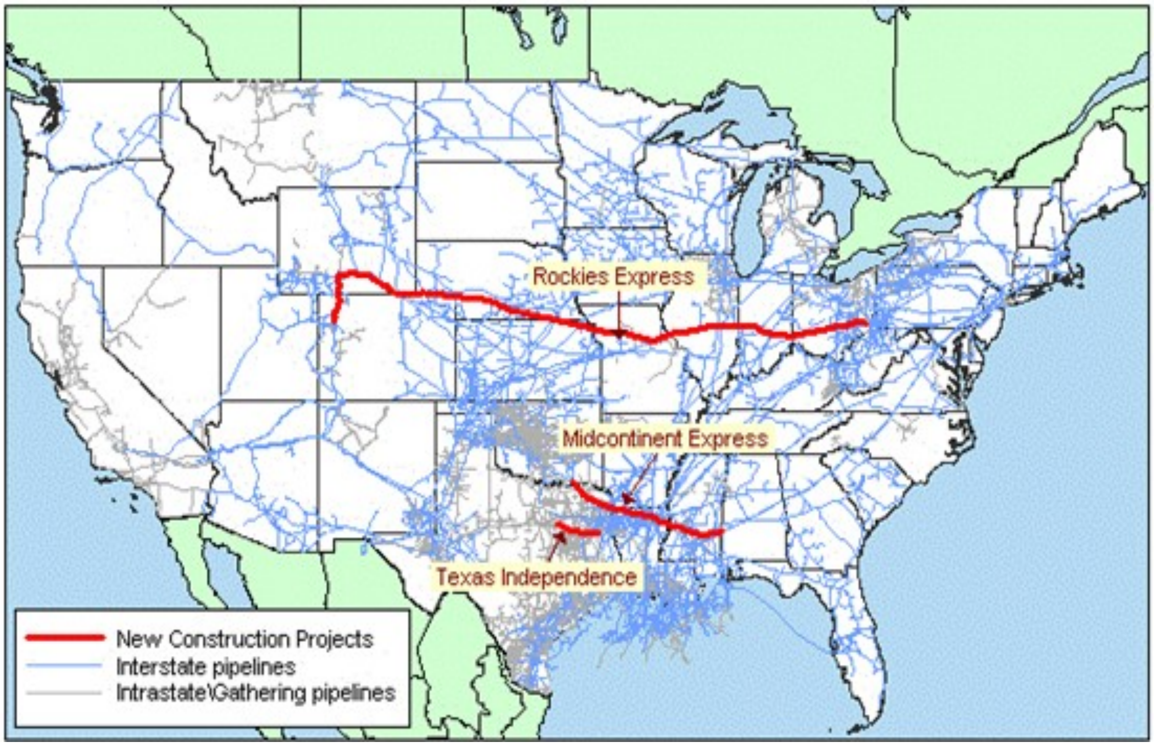


Source: Weinstein et al. (2010) using data from the EIA

Figure 20: Energy production costs by energy source[21]

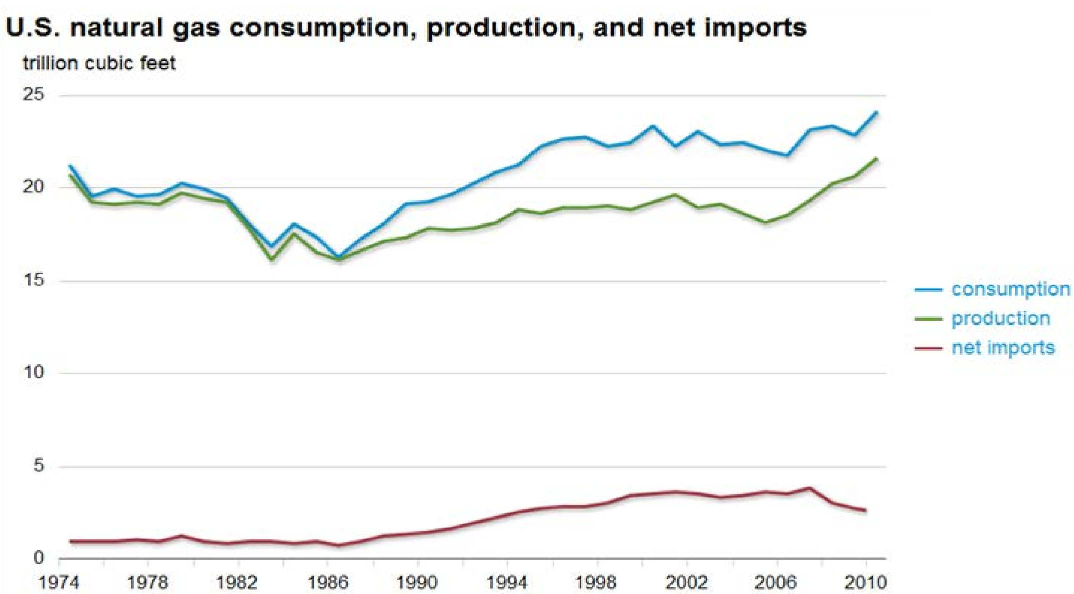
Natural gas is often viewed as a bridge between a reliance on carbon emitting fossil fuels and an energy industry comprised of some mix of alternative energy sources with far less reliance on foreign energy and carbon emitting energy sources. Figure 23 on page 22 shows the life cycle emissions rates for various sources of electricity generation. Although natural gas emits significantly more carbon than nuclear and alternative energy sources, it does emit far less than coal. Thus, as table 3 showed, switching from coal to natural gas will not only save money on energy costs it will also reduce carbon emissions. Natural gas combustion emits lower levels of carbon dioxide, nitrogen oxide, and sulfur dioxide than both coal and oil. Yet,

20. It should also be noted that a decoupling of natural gas prices from oil prices has realigned markets (Southgate and Daniels, 2011).
21. The average levelized cost is the present value of all costs including building and operating the plants.



Source: EIA, GasTran Natural Gas Transportation Information System.

Figure 21: Natural Gas Infrastructure



Source: EIA

Figure 22: Increasing Production Reduces Imports

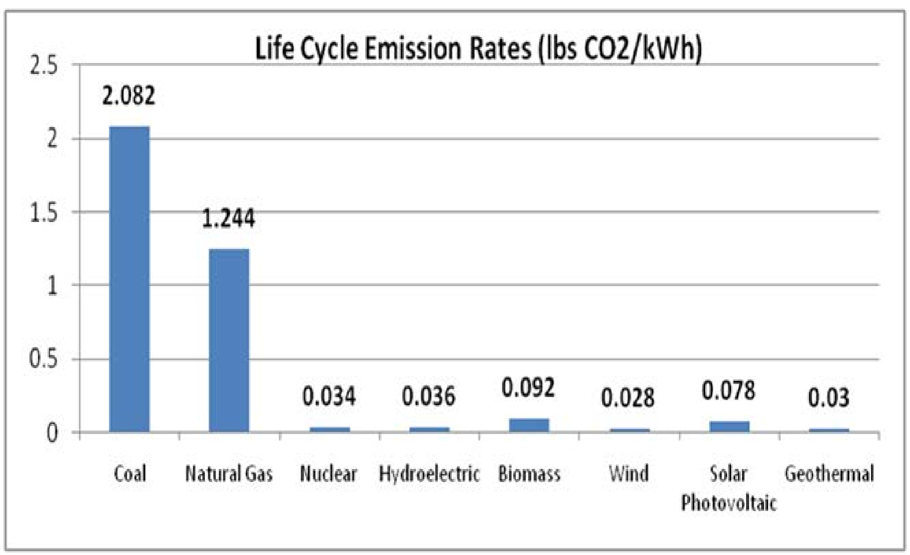
Howarth et al. (2011) find that the carbon emission benefits of natural gas are less when it extracted using hydraulic fracturing compared to conventional methods because of the water and wastewater transportation.

Despite the potential emissions advantages of natural gas, significant concerns have been raised about the environmental impact of natural gas extraction with a Duke University study finding elevated levels of methane in water near drilling sites (Osborn et al., 2011) and the EPA's recent announcement that hydraulic fracturing chemicals polluted water sources in Wyoming (The Associated Press).

The environmental concerns with natural gas have been focused on the hydraulic fracturing process and its impact on water sources. The importance of understanding the hydraulic fracturing process is essential in understanding its potential environmental effects. If cracks aren't able to be controlled or predicted during hydraulic fracturing or somehow disturb the ground, then natural gas or fracturing fluid containing toxic chemicals may shift or migrate to aquifers affecting drinking water. However, hydraulic fracturing typically occurs at depths well below the level of aquifers and drinking water. At thousands of feet below water sources, it is unlikely that hydraulic fracturing would contaminate water sources in Ohio. A 2004 EPA report found that, although fluids migrated unpredictably, hydraulic fracturing did not affect underground drinking water and posed no health risk. Representatives of the natural gas industry have made similar claims that hydraulic fracturing has never contaminated drinking water sources. These claims were used to exempt the natural gas industry from the Clean Water Act and the Safe Drinking Water Act when Congress enacted the 2005 Energy Policy Act.

Although the hydraulic fracturing method of injecting fluids deep below the aquifer level may not be a source of contamination, this level and aquifers themselves must be drilled through. Casing failures in the drilling process may cause fracturing fluids or natural gas to escape and pollute aquifers and local water sources. There are also concerns over spills that can occur during transport or impoundment failures. Thus, whether hydraulic fracturing has contaminated water sources becomes an issue of semantics as to whether the cause is the actual hydraulic fracturing or the drilling, extracting, and spills. Because of the potential impacts on water sources, it is important to be aware of the location of water sources compared to the location of shale resources. Figures 24 and 25 on the next page show the water resources of the US (aquifers are differentiated by various colors). US water resources and shale resources are clearly geographically overlapping though they are at different depths (including in Ohio and Pennsylvania).

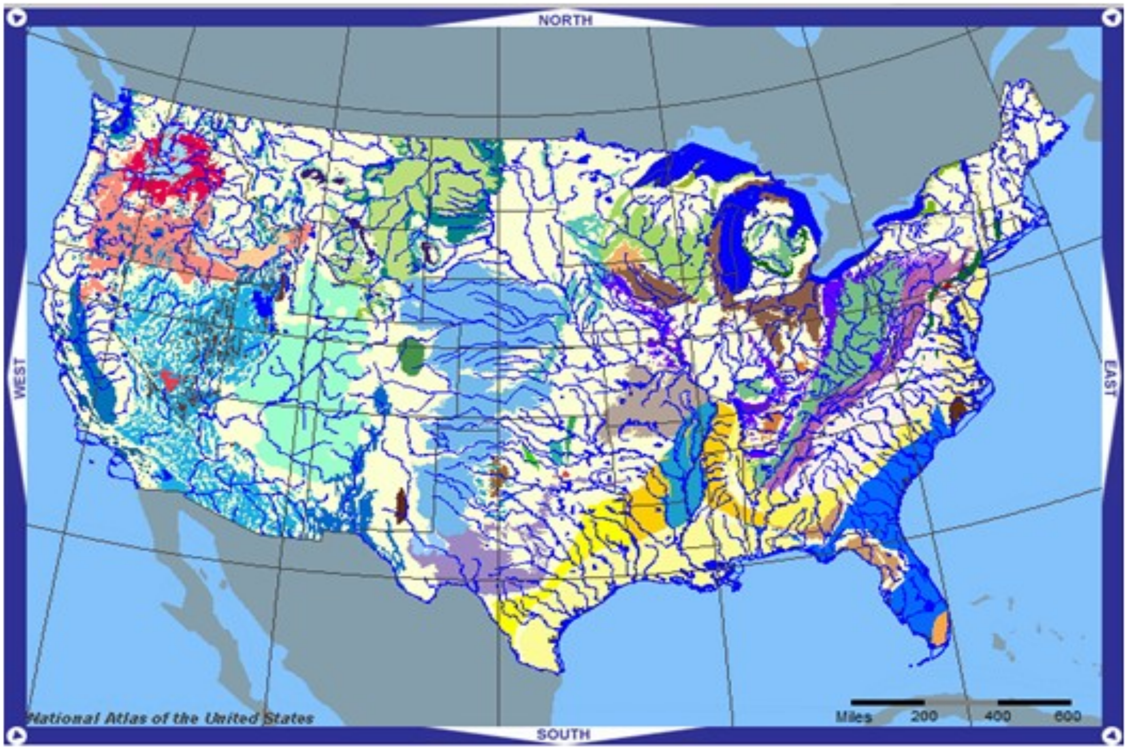
In addition to accidental contamination in the drilling and extraction process, water use and disposal are also concerns. The hydraulic fracturing method requires at least a million gallons of water per well that is combined with chemicals and sand. Sapien (2009) notes that approximately 9 million gallons of wastewater per day were produced from Pennsylvania wells in 2009, and this amount is expected to increase. This water byproduct contains elements and chemicals such as cadmium and benzene that are known to cause cancer. There may be other toxic chemicals in the hydraulic fracturing fluid mix though energy companies have continually refused to disclose these chemicals for proprietary reasons. Water byproducts also contain Total Dissolved Solids (TDS) that can make the water five times as salty as



Source: Weinstein et al. (2010) using data from Meier (2002)

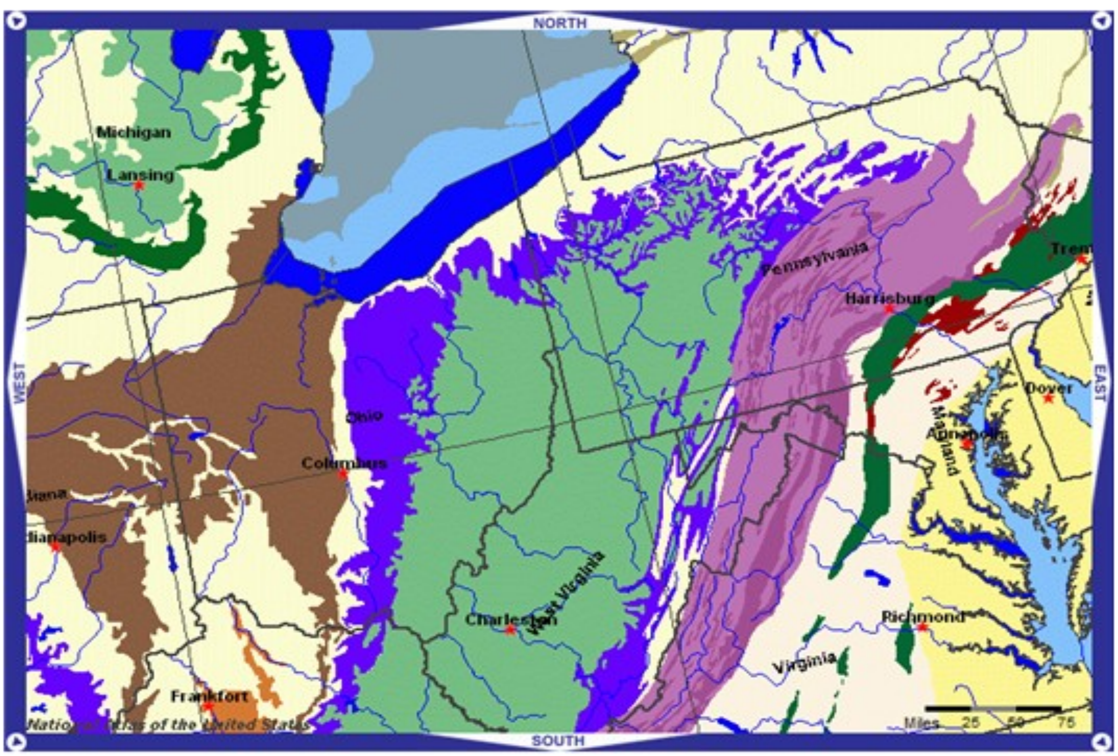
Figure 23: Carbon Emissions by Electricity Source[22]

22. Life cycle emissions rates include the total aggregated carbon emissions over the life cycle of the fuel, including extraction, production, distribution, and use.



Source: NationalAtlas.Gov

Figure 24: US Aquifer, Stream, and Waterbed Resources



Source: NationalAtlas.Gov

Figure 25: Ohio and Pennsylvania Aquifer, Stream, and Waterbed Resources

seawater. Although some of this water is left behind and some can be reused, there is still a significant amount that must be treated and disposed. Water byproducts must be stored in either open wells, closed containment wells, or injected back into the ground. Open wastewater wells can lead to air pollution as it evaporates and water contamination if the lining fails, but this method is less expensive than other methods. There are additional air pollution concerns with the increased traffic resulting from water transportation, flaring, etc.

There are also environmental costs in the form of noise pollution. Ohio residents may simply not want to look at or hear natural gas rigs in their backyard or heavy equipment driving through the countryside. Hydraulic fracturing does limit the number of rigs used compared to conventional methods.

The potential environmental impact of hydraulic fracturing on water in Ohio needs to be accounted for when estimating the economic costs of natural gas. Just as the employment and income effects for Ohio were estimated using Pennsylvania as a case study, the potential environmental impacts of hydraulic fracturing and natural gas drilling on Ohio can be approximated by examining incidents in Pennsylvania. Whether the source of contamination is from the migration of fluids and gas underground, drilling or extraction accidents, or improper disposal of water byproducts, it is important to understand what Pennsylvania residents have experienced. After gaining a better understanding of the environmental impacts, then it is important to determine the source of the contamination, how it can be prevented, and whether new regulations are needed to protect the Ohio environment and its drinking water.

Pennsylvania Environmental Concerns:

In 2008, Lustgarten noted that more than 1,000 cases of suspected contamination have been documented in Colorado, New Mexico, Alabama, Ohio, and Pennsylvania. Incidents of contamination have been most publicized in Dimock, PA. Dimock is located in Susquehanna County in northeastern Pennsylvania where natural gas development is most pronounced. Dimock is a struggling rural area with approximately 1,300 residents and nearly 1 in 7 is unemployed. Residents hoped the natural gas industry would turn their economy around. Instead, the controversial documentary *Gasland* contends it environmentally turned it upside down.[23] The documentary begins and ends in Dimock and includes footage of residents lighting their tap water on fire. After natural gas drilling began in Dimock, Lustgarten notes that several of the residents' wells have exploded. Affected residents now buy water from outside sources. The Pennsylvania Department of Environmental Protection (DEP) believes a casing failure is to blame for the drinking water contamination and is holding Cabot Oil responsible. Cabot Oil has agreed to supply clean water to some of the affected residents and has been required to pay compensation to many residents. In September of 2009, Cabot Oil spilled nearly 8,000 gallons of fracturing fluids that seeped into a nearby creek.

Evidence of fracturing fluid has now been found in drinking water sources including the Monongahela River. In response to these cases and others, the natural gas industry has been quick to label these events as unfortunate but highly unlikely implying that these cases are the result of just a few "bad apples." In some cases they claim methane has always existed in these water sources, but simply went unnoticed until now. Without conducting baseline water testing before drilling, the burden of proof required by the courts in many cases cannot be met to prove otherwise.

The *New York Times* publicized recent peer-reviewed research by Duke University showing an association between drinking water contamination and natural gas extraction. The study by Osborn et al. (2011) conducted research at 68 private water wells in Pennsylvania and New York finding that methane concentrations were 17 times higher for wells near active drilling, with some wells having methane levels requiring "immediate action." However, the study found no evidence of fracturing fluid contamination in these wells. The prevalence and commonality of these incidents, coupled with the devastating impacts, seem to suggest the need for caution. Some chemicals, particularly in the produced water, may be harder for residents to detect than methane, especially when the industry refuses to disclose all of the components of the fracturing fluid mixture. Regardless, it is clear that more information on the environmental impacts of natural gas is needed in deciding any need for further regulations.

Recent EPA Action:

Recognizing the need to further understand the true impacts of natural gas extraction, specifically hydraulic fracturing, Congress directed the EPA to

23. It should be noted that *Gasland* did not undergo the scientific scrutiny of a peer-reviewed journal article and because no baseline testing was conducted in *Gasland* or any research thus far, it is difficult to discern the source of contamination and whether it came from gas industry activity. Hopefully, US EPA research will answer these questions in 2012.

study the impact hydraulic fracturing has on drinking water and groundwater. The EPA (2011) identified seven case studies, three of which are in Pennsylvania, to examine the lifecycle of a well and whether hydraulic fracturing affects drinking water. The EPA will also collect information from computer modeling, laboratories, and other data from the industry, states, and communities. Initial results of this study are expected in late 2012. Hence, it is unlikely that there will be any national regulations in the near future, while Ohio hydraulic fracturing in the Marcellus and Utica has already begun. Until Congress or the EPA acts, the regulation of hydraulic fracturing is left to the states.[24]

Ohio Environmental Protection:

Because the EPA and Congress have essentially relegated any regulatory authority to the states, this increases the importance of the Ohio EPA and the Ohio Division of Mineral Resources Management (ODNR) for environmental regulations. The Ohio EPA (2011) states that ODNR has primary regulatory authority over natural gas drilling, including the treatment and disposal of wastewater in the hydraulic fracturing process. The Ohio EPA also has water quality certification requirements to help preserve wetlands, streams, rivers, and other water sources. The appendix includes a list of the regulatory authority between ODNR and the Ohio EPA.

The Ohio Farm Bureau's Dale Arnold contends that Ohio has better regulatory authority over the oil and gas industry compared to Pennsylvania. Although the Cuyahoga River fire in 1969 in Cleveland, OH was not associated with fracturing, Scott (2009) notes it was a catalyst not only for Ohio environmental regulations, but also the national Clean Water Act in 1972 and the creation of the US EPA (and Ohio EPA). Dale Arnold reckons that even before the Cuyahoga fire, Ohioans had built a "collective consciousness," learning from past oil and gas industry experiences, preparing themselves for future waves.

Ohio's collected experiences and advanced environmental regulations have certainly left the state better prepared to handle the wastewater produced from hydraulic fracturing than Pennsylvania. Much of the wastewater from Pennsylvania comes to Ohio injection wells. Hunt (2011) notes that in June of 2010, Ohio quadrupled out-of-state fees to limit brine coming in from Pennsylvania and other states while anticipating the increased disposal needs of Ohio's own burgeoning natural gas industry. Despite the increased prices, nearly half of the brine in Ohio injection wells came from Pennsylvania after its officials banned 27 treatment plants from dumping brine into streams. This highlights the importance of Ohio properly addressing the issue of wastewater.

Ohio has made strides in environmental regulations through the drilling permitting process. Permits or "frac tickets" are required for gas companies planning on using hydraulic fracturing to extract natural gas. A frac ticket requires that companies disclose the chemicals used in the fracturing fluid. If a spill or casing failure should occur, Ohio will know many of the possible contaminants for testing. Ohio's permitting also allows residents to more easily prove their water has been contaminated with fracturing fluid.

Because many of the residents that will be most affected by shale gas development are farmers, the Ohio Farm Bureau is advising farmers and residents on the leasing process and is recommending that residents establish independent baseline water and soil quality measures that have been so notably missing from Pennsylvania and elsewhere. In addition, it is now standard practice in Ohio for gas companies to do their own baseline testing on all residents' water within 3,000 yards of the drilling site.

Even with better regulations, accidents may happen. Lustgarten (2009) recounts a 2007 incident of a house explosion in Bainbridge, OH. In a later report, ODNR found that a faulty concrete casing failure from a nearby natural gas well caused methane to be pushed into an aquifer during hydraulic fracturing, which then found its way into the plumbing, building up in the basement of the house.

The Cuyahoga fire itself and other serious environmental incidents have a more profound impact than just on the environment. Congressmen Louis Stokes said in regards to the Cuyahoga fire, "It portrayed a totally different image of Cleveland than the image of a productive, progressive city that was making news of a progressive nature" (as quoted in Scott, 2009). The lessons of the Cuyahoga fire resonate for natural gas development. The negative impacts on the environment can affect communities in lasting ways that cannot be exactly quantified but still require consideration.

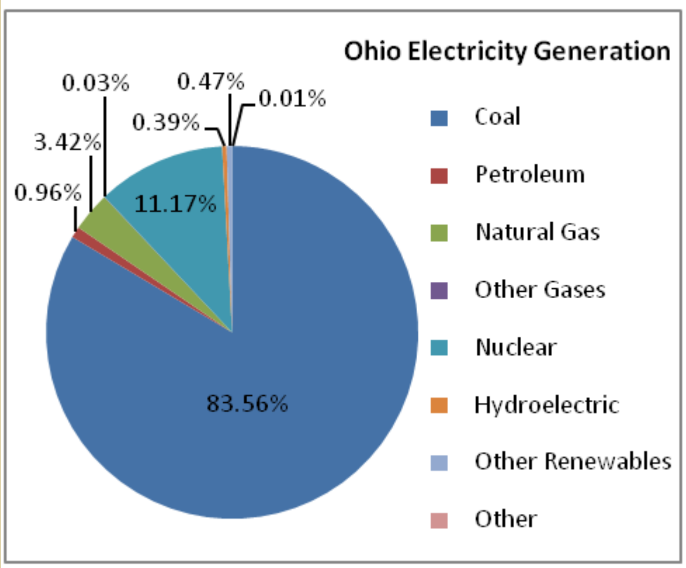
24. In 2009, members of Congress introduced the Fracturing Responsibility and Awareness of Chemicals Act, also called the "Frac Act," to undo the natural gas industry's exemption from the Safe Drinking Water Act and require the industry to disclose the chemicals used in the fracturing process. Though reintroduced in March of 2011, it is not expected to pass.

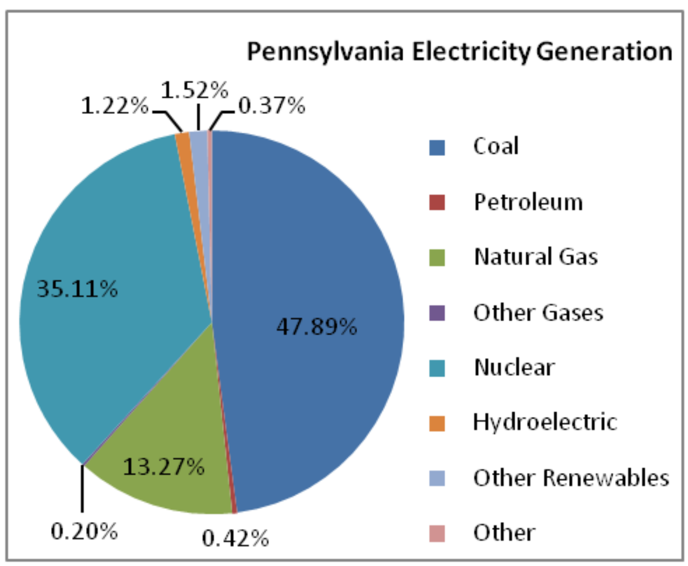
Conclusion

Hydraulic fracturing has made natural gas extraction possible and more productive in shale resources that were previously deemed uneconomical. This has brought a new wave of natural gas extraction to Ohio and other areas. However, recent experiences with hydraulic fracturing have also opened a new debate about the costs and benefits of natural gas extraction. Gary Walzer, Principle Engineer at EMTEC, states that natural gas has the potential to be a substantial source of domestic energy that is cleaner than coal with lower emissions. This has the potential to decrease US reliance on coal. Compared to Pennsylvania, Ohio clearly has a less diversified energy portfolio that relies heavily on carbon emitting coal. Based on electricity generation alone, Ohio is emitting significantly more carbon than Pennsylvania. Natural gas could be a significant first step for Ohio to diversify its energy portfolio and reduce carbon emissions.

Compared to coal, natural gas is not only cleaner but also less expensive to produce electricity. Producing energy in close proximity to where it is needed further lowers energy prices for consumers and industry. Unlike alternative energy, there are market forces pushing for the production of natural gas without the use of inefficient subsidies, though all of the social costs of natural gas (and coal) are not sufficiently priced. Low natural gas prices provide evidence that it is highly efficient for producing electricity. This efficiency is one reason why natural gas is associated with fewer jobs than coal—but the lower costs make the rest of the economy more competitive.

Does all of this also mean that natural gas will create significant numbers of job for Ohioans? Previous studies on the economic impacts of natural gas appear to have widely overstated the economic impacts. This is not surprising, as these studies are typically industry-funded and industry-funded studies are usually not the best sources of information for economic effects (regardless of the industry). One reason for the overstatement is the energy industry is generally very capital intensive. Alan Krueger, Chief Economist and Assistant Secretary for Economic Policy at the US Department of Treasury stated in 2009, “The oil and gas industry is about 10 times more capital intensive than the US economy as a whole… suggesting these tax subsidies are not effective means for domestic job creation” (US Department of Treasury). The energy industry as a whole also does not account for a significant share of employment. Even if the natural gas industry experiences significant job growth, its employment share is too small to have any significant effect on unemployment rates and on the economy (with the exception of remote rural areas such as in rural Western North Dakota). Previous studies on the economic impacts also fail to account for the displacement effects that the natural gas industry will have on other industries. Finally, from a national perspective greater natural gas production will displace other fossil fuels and their workers as they are no longer needed, in





Source: US EIA

Figure 26: 2009 Electricity Generation Profiles

particular coal.

We use Pennsylvania as a case study to estimate the employment effects of drilling that Ohio can realistically expect. Our analysis shows the employment effects of natural gas are modest given the size of the Ohio and Pennsylvania economy. We show this through (1) an assessment of impact analysis, (2) by comparing drilling counties with similarly matched non-drilling counties in Pennsylvania, (3) statistical regressions on the entire state of Pennsylvania, (4) employment comparisons with North Dakota's Bakkan shale region, and (5) an examination of the employment life cycle effects of natural gas and coal per kilowatt of electricity. Our results are not unexpected as the economic literature has long pointed to the adverse effects of natural resource development through phenomenon such as the "natural resources curse" and Dutch Disease. Likewise, a recent Cornell University study found similar overstatements by the oil industry in terms of job forecasts for the Keystone XL pipeline (Cornell University ILR School Global Labor Institute, 2011). On the other hand, our approaches suggest that natural gas activity will increase per-capita income. We expect this is primarily among landholders receiving royalties/lease payments and through higher wages in the industry. Thus, we expect a short-term infusion of income in affected economies.

As Christopherson and Rightor (2011) point out, it is important to realize these are fairly short-term estimates and may still not account for the cycle of the natural resource boom. The initial boom causes competition for labor in the short-term, bidding up wages. This makes the area less competitive and "crowds out" other sectors, especially those that rely on low cost labor such as agriculture and tourism. As housing prices are bid up, this will also further displace low-income workers. In the long-run, the business climate may suffer as there are fewer businesses that are unrelated to the oil and gas industry, which makes the local economy less diverse and more vulnerable to economic shocks. Our advice to counties experiencing drilling activity is to ensure they properly pay for infrastructure needs upfront, place monies in reserves for after the boom, and build up local assets such as schools in order to produce lasting benefits from energy development.

Finally, the environmental costs of natural gas need to be realistically addressed by the industry and regulators. Although natural gas can reduce carbon emissions compared to coal and other fossil fuels, there are concerns about its effect on drinking water. Because Ohio has been able to learn from Pennsylvania's experiences with the oil and gas industry, Ohio seems better prepared to deal with the environmental risks. Nevertheless, a realistic assessment of the environmental costs of natural gas should also include the environmental opportunity cost of natural gas. Natural gas mainly displaces coal, which emits even more carbon and also has additional environmental and safety concerns. A Clean Air Task Force report unequivocally states that "coal irreparably damages the environment." Coal poses significant health risks to both miners and nearby residents. Despite the number of years the US has been extracting coal, there are still significant issues with its waste products. Most recently on Oct. 31, 2011 a bluff collapse caused coal ash to be spilled into Lake Michigan (Jones and Behm, 2011). In 2008, the *New York Times* reported that experts called the Tennessee ash flood that dumped over 1.1 billion gallons of coal ash waste "one of the largest environmental disasters of its kind" (Dewan, 2008). We are not understating the environmental costs of natural gas, but rather putting it into perspective in relation to the environmental costs of coal, which is natural gas's main competitor.

Although we should not expect natural gas to be a big job creator, there are significant benefits to producing natural gas that are getting lost in the hype of job creation. Raising expectations that natural gas will not be able to meet is setting Ohio residents up to be disappointed. The true benefits of natural gas need to be highlighted while putting the costs into perspective. Likewise, Ohio needs to plan today about how to make some of the gains from the energy boom permanent. Among many things, this will require innovative policies and funding models to ensure that infrastructure is paid for today and there is adequate funding to maintain that infrastructure in the future.

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Appendix 1: County Comparison Mining (blue) vs. Non-Mining (green)

See notes to figures 15-18 for more details. Southern drilling counties include Washington, Greene, and Fayette. Southern non-drilling counties include Franklin, Perry, and Cumberland. Northeastern drilling counties include Tioga, Bradford, and Susquehanna. Northeastern non-drilling counties include Union, Columbia, and Carbon.

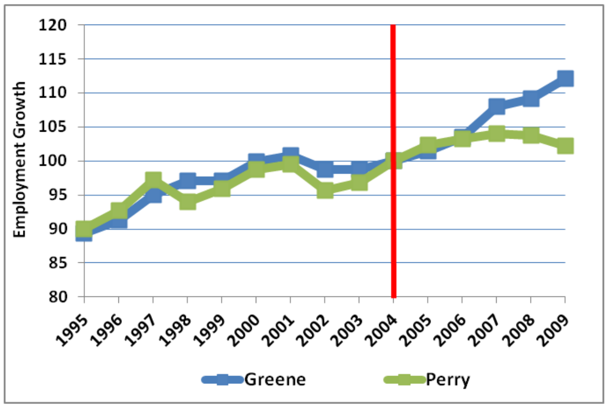

Figure 27: Employment Growth Comparison Greene vs. Perry

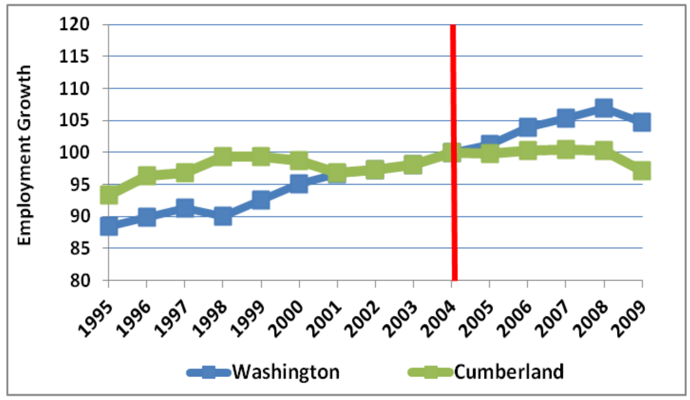

Figure 28: Employment Growth Comparison Washington vs. Cumberland

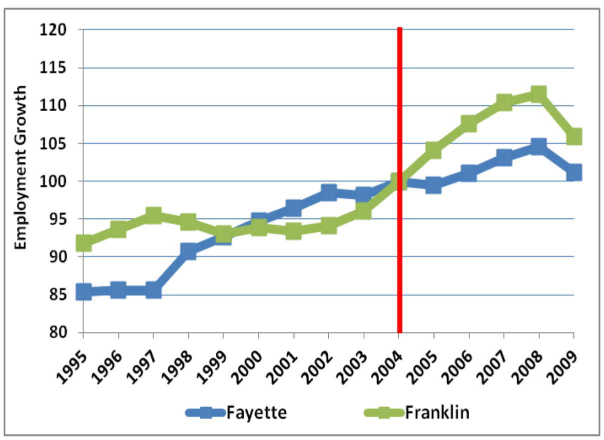

Figure 29: Employment Growth Comparison Fayette vs. Franklin

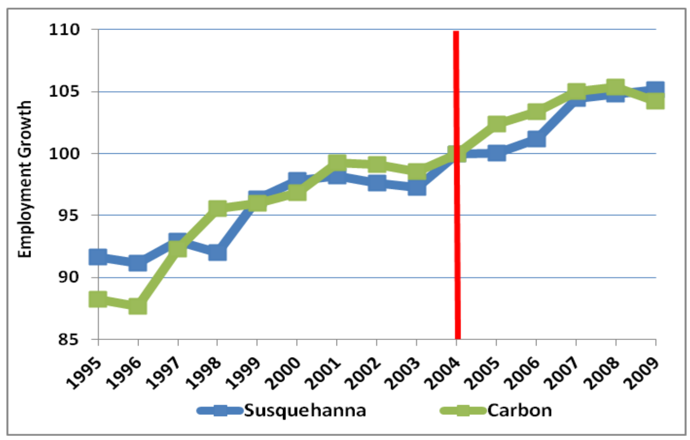

Figure 30: Employment Growth Comparison Susquehanna vs. Carbon

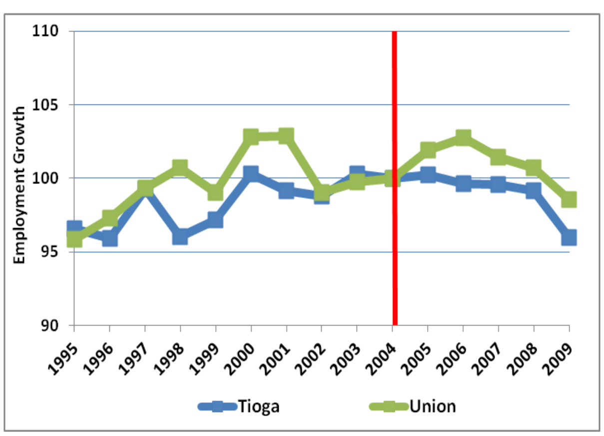

Figure 31: Employment Growth Comparison Tioga vs. Union

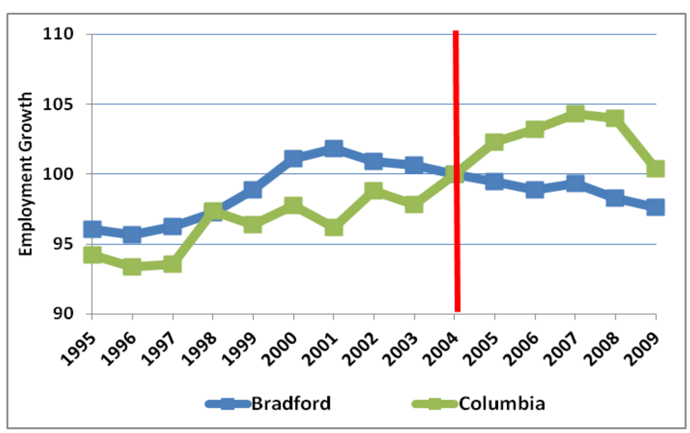

Figure 32: Employment Growth Comparison Bradford vs. Columbia

Appendix 1: County Comparison Mining (blue) vs. Non-Mining (green)

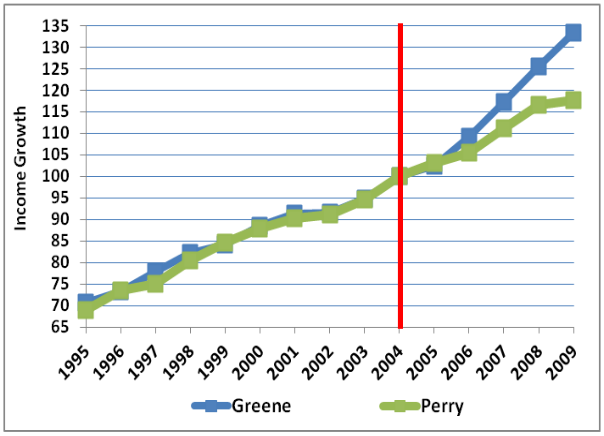

Figure 33: Per Capita Income Growth Comparison
Greene vs. Perry

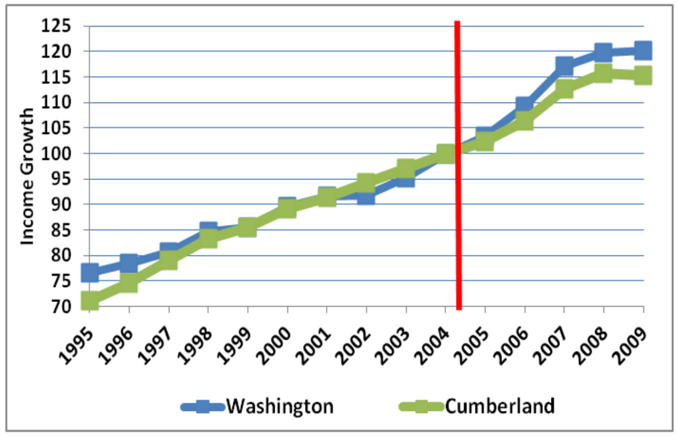

Figure 34: Per Capita Income Growth Comparison
Washington vs. Cumberland

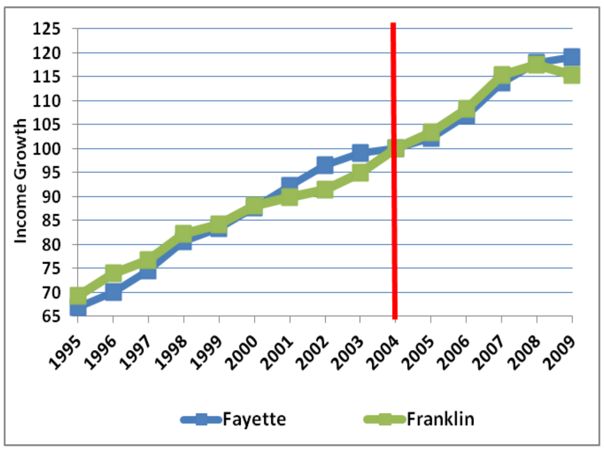

Figure 35: Per Capita Income Growth Comparison
Fayette vs. Franklin

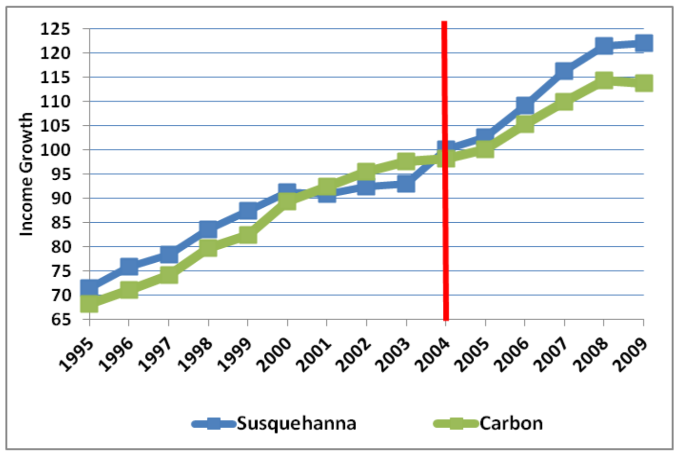

Figure 36: Per Capita Income Growth Comparison
Susquehanna vs. Carbon

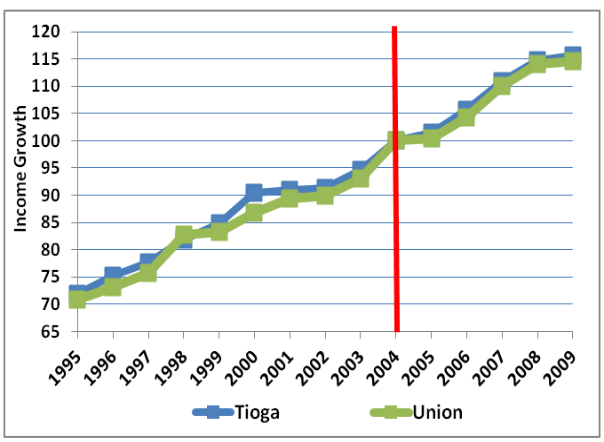

Figure 37: Per Capita Income Growth Comparison
Tioga vs. Union

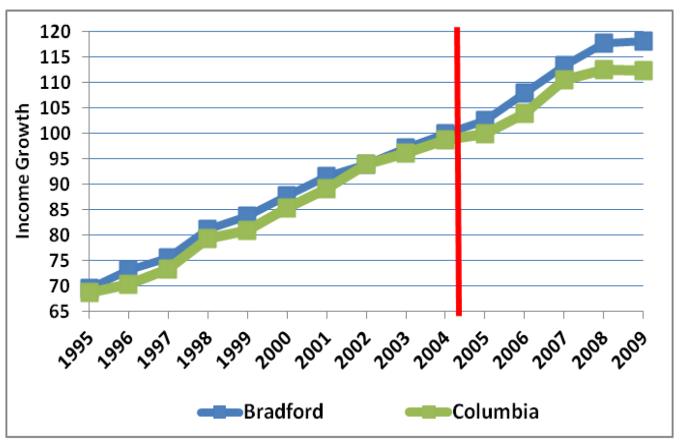

Figure 38: Per Capita Income Growth Comparison
Bradford vs. Columbia

Appendix 2: Statistical Methodology

In 2005, drilling began in Pennsylvania in a number of counties with natural gas potential due to the location of resources in the Marcellus shale. The choice of county to develop shale gas was based on the random occurrence of natural resources and not prior economic conditions. However, there may be other inherent county differences between drilling and non-drilling counties. For example, counties with drilling tend to be rural. Likewise, counties tend to have many factors that influence their economic growth such as the quality of its government, distance to urban centers, and educational and demographic attributes of the population. These factors are either constant or change very slowly. We treat these as county fixed effects on county growth.

We want to measure the economic impacts of drilling. Equation 2 shows the impact of the number of wells on the percent employment growth (Y_{i1}) for county i in period 1 (2005-2009). However, the empirical estimation of this impact would not be able to account for county fixed effects (C_i). This could bias the estimates of the impact of drilling by omitting relevant variables that differentiate drilling counties from non-drilling counties. Thus, equation 3 estimates the impact of drilling since 2005 on the difference in employment growth between period 1 and period 0 (2001-2005). The county fixed effect is differenced out and thus there should not be omitted variable bias.

Table 5 shows the results of this estimation using the total number of well drilled since 2005. We also include additional controls to better account for differences in the way larger or wealthier counties may have reacted to shale development, or more importantly, how wealthier or more urban counties were differentially affected by effects of the housing bubble/bust and the Great Recession. Using the total number of wells parameter estimate, Table 5 shows that drilling has a small and statistically insignificant impact on percent employment growth.

$$Y_{i0} = \beta_0 + \beta_1(\text{Number of Wells})_{i0} + C_i + \varepsilon_{i0} \quad (1)$$
$$Y_{i1} = \beta_0 + \beta_1(\text{Number of Wells})_{i1} + C_i + \varepsilon_{i1} \quad (2)$$
$$Y_{i1} - Y_{i0} = \beta_0 + \beta_1(\Delta \text{ Number of Wells}) + \varepsilon_i \quad (3)$$

A similar method is used to empirically estimate the impact of drilling on per capita income with results presented Table 6. In this case, drilling has a statistically significant impact on percent per capita income growth.

2005-09 Percent Employment Growth Minus 2001-05 Percent Employment Growth	Parameter Estimate	t-value
	Difference in Employment Change	
Total Wells 05-09	**1.769E-05**	**1.14**
2001 Log Population	0.023	2.64
2001 Log Per Capita Income	-0.096	-1.55
N	67	
R2	0.118	
Adjusted-R2	0.076	

Table 5: Impact of drilling on employment

2005-2009 Percent Income Growth Minus 2001-05 Percent Income Growth	Parameter Estimate	t-value
	Difference in Income Change	
Total Wells 05-09	**2.515E-05**	**2.11**
2001 Log Population	0.084	2.53
2001 Log Employment	-0.086	-2.76
N	67	
R2	0.205	
Adjusted-R2	0.167	

Table 6: Impact of drilling on income

Another method to develop a counterfactual to compare how drilling counties would have done if there was no drilling is to use a difference in difference approach. The difference in differences approach treats drilling as a treatment in a natural experiment. The difference in differences estimates the causal effect of the difference between the treatment and control group before and after treatment (drilling). This is shown below in equation 4 where i=0 represents non-drilling counties and i=1 represents drilling counties; t=0 is still the first time period (2001-2005) and t=1 is the second time period (2005-2009).

$$[E(Y_{11})-E(Y_{01})] - [E(Y_{10})-E(Y_{00})] \quad (4)$$

To measure the impact of drilling on the employment growth of county i in time period t (Y_{it}), a control group needs to be established (non-drilling counties). This is further expanded in equation (5). The main effect of the treatment group, β_1 controls for the difference between the treatment and control in period 0. The main effect of the second period, β_2 controls for the difference between the effects of the second period compared to the first period. The parameter of interest, β_3 estimates equation 4: the impact of the number of wells had on counties since drilling began in 2005. Through asymptotics, it can be shown that the probability limit of the estimate of β_3 is equivalent to equation 4.

$$Y_{it} = \beta_0 + \beta_1(\text{Number of Wells}_{it}) + \beta_2 t + \beta_3(t^*\text{Number of Wells}_{it}) + \varepsilon_i \qquad (5)$$

Table 7 shows the empirical estimation of equation 4 for employment growth. The results are similar to those in Table 5 with the impact of drilling on employment being small and statistically insignificant. Table 8 reports the estimates of equation 5 for per capita income growth. Similar to Table 6, it shows that drilling appears to have had a positive statistically significant impact on per capita income growth.

Percent Employment Growth	Parameter Estimate	t-value
Time Period*Total Wells	**1.763E-05**	**0.91**
Time Period	-0.05	-4.12
Total Wells	-3.240E-06	-0.23
Log Population	-0.005	-0.85
Log Per Capita Income	0.066	1.69
N	134	
R2	0.125	
Adjusted-R2	0.091	

Table 7: Impact of drilling on employment

Percent Income Growth	Parameter Estimate	t-value
Time Period*Total Wells	**3.119E-05**	**2.52**
Time Period	0.0253	3.51
Total Wells	-3.310E-06	-0.37
Log Population	0.009	0.55
Log Employment	-0.007	-0.43
N	134	
R2	0.205	
Adjusted-R2	0.167	

Table 8: Impact of drilling on income

Appendix 3: Ohio Environmental Regulatory Authority

Summary of ODNR and Ohio EPA regulatory authority over oil/gas drilling and production activities

	Ohio Department of Natural Resources	Ohio Environmental Protection Agency
Drilling in the shale deposits	✓ Issues permits for drilling oil/gas wells in Ohio. ✓ Sets requirements for proper location, design and construction of wells. ✓ Inspects and oversees drilling activity. ✓ Requires controls and procedures to prevent discharges and releases. ✓ Requires that wells no longer used for production are properly plugged. ✓ Requires registration for facility owners with the capacity to withdraw water at a quantity greater than 100,000 gallons per day.	✓ Requires drillers obtain authorization for construction activity where there is an impact to a wetland, stream, river or other water of the state. ✓ Requires drillers obtain an air permit to install and operate (PTIO) for units or activities that have emissions of air pollutants.
Wastewater and drill cutting management at drill sites	✓ Sets design requirements for on-site pits/lagoons used to store drill cuttings and brine/flowback water. ✓ Requires proper closure of on-site pits/lagoons after drilling is completed. ✓ Sets standards for managing drill cuttings and sediments left on-site.	✓ Requires proper management of solid wastes shipped off-site for disposal.
Brine/flowback water disposal	✓ Regulates the disposal of brine and oversees operation of Class II wells used to inject oil/gas-related waste fluids. ✓ Reviews specifications and issues permits for Class II wells. ✓ Sets design/construction requirements for Class II underground injection wells. ✓ Responds to questions/concerns from citizens regard safety of drinking water from private wells from oil/ natural gas drilling.	
Brine/flowback water hauling	✓ Registers transporters hauling brine and oil/gas drilling-related wastewater in Ohio.	
Pumping water to the drill site from a public water supply system		✓ Requires proper containment devices at the point of connection to protect the public water system.

Source: EPA (2011)

The White House

Office of the Press Secretary

For Immediate Release January 24, 2012

Remarks by the President in State of the Union Address

United States Capitol
Washington, D.C.

9:10 P.M. EST

THE PRESIDENT: Mr. Speaker, Mr. Vice President, members of Congress, distinguished guests, and fellow Americans:

Last month, I went to Andrews Air Force Base and welcomed home some of our last troops to serve in Iraq. Together, we offered a final, proud salute to the colors under which more than a million of our fellow citizens fought -- and several thousand gave their lives.

We gather tonight knowing that this generation of heroes has made the United States safer and more respected around the world. (Applause.) For the first time in nine years, there are no Americans fighting in Iraq. (Applause.) For the first time in two decades, Osama bin Laden is not a threat to this country. (Applause.) Most of al Qaeda's top lieutenants have been defeated. The Taliban's momentum has been broken, and some troops in Afghanistan have begun to come home.

These achievements are a testament to the courage, selflessness and teamwork of America's Armed Forces. At a time when too many of our institutions have let us down, they exceed all expectations. They're not consumed with personal ambition. They don't obsess over their differences. They focus on the mission at hand. They work together.

Imagine what we could accomplish if we followed their example. (Applause.) Think about the America within our reach: A country that leads the world in educating its people. An America that attracts a new generation of high-tech manufacturing and high-paying jobs. A future where we're in control of our own energy, and our security and prosperity aren't so tied to unstable parts of the world. An economy built to last, where hard work pays off, and responsibility is rewarded.

We can do this. I know we can, because we've done it before. At the end of World War II, when another generation of heroes returned home from combat, they built the strongest economy and middle class the world has ever known. (Applause.) My grandfather, a veteran of Patton's Army, got the chance to go to college on the GI Bill. My grandmother, who worked on a bomber assembly line, was part of a workforce that turned out the best products on Earth.

The two of them shared the optimism of a nation that had triumphed over a depression and fascism. They understood they were part of something larger; that they were contributing to a story of success that every American had a chance to share -- the basic American promise that if you worked hard, you could do well enough to raise a family, own a home, send your kids to college, and put a little away for retirement.

The defining issue of our time is how to keep that promise alive. No challenge is more urgent. No debate is more important. We can either settle for a country where a shrinking number of people do really well while a growing number of Americans barely get by, or we can restore an economy where everyone gets a fair shot, and everyone does their fair share, and everyone plays by the same set of rules. (Applause.) What's at stake aren't Democratic values or Republican values, but American values. And we have to reclaim them.

Let's remember how we got here. Long before the recession, jobs and manufacturing began leaving our shores. Technology made businesses more efficient, but also made some jobs obsolete. Folks at the top saw their incomes rise like never before, but most hardworking Americans struggled with costs that were growing, paychecks that weren't, and personal debt that kept piling up.

In 2008, the house of cards collapsed. We learned that mortgages had been sold to people who couldn't afford

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January 25, 2012 1:30 AM

2012 State Of The Union Address Enhanced Version

BLOG POSTS ON THIS ISSUE

May 19, 2013 4:33 PM EDT

President Obama Delivers the Commencement Address at Morehouse College

President Obama delivers the commencement address to the 2013 graduates of Morehouse College in Atlanta, GA.

May 18, 2013 7:30 PM EDT

First Lady Delivers Commencement Addresses at Bowie State, Martin Luther King Jr. Magnet High School

First Lady Michelle Obama delivers the commencement addresses at Bowie State University and Martin Luther King Jr. Magnet High School.

May 18, 2013 6:00 AM EDT

Weekly Address: The President Talks About How to Build a Rising, Thriving Middle Class

President Obama talks about his belief that a rising, thriving middle class is the true engine of economic growth, and that to reignite that engine or understand them. Banks had made huge bets and bonuses with other people's money. Regulators had looked the other way, or didn't have the authority to stop the bad behavior.

It was wrong. It was irresponsible. And it plunged our economy into a crisis that put millions out of work, saddled us with more debt, and left innocent, hardworking Americans holding the bag. In the six months before I took office, we lost nearly 4 million jobs. And we lost another 4 million before our policies were in full effect.

Those are the facts. But so are these: In the last 22 months, businesses have created more than 3 million jobs. (Applause.)

Last year, they created the most jobs since 2005. American manufacturers are hiring again, creating jobs for the first time since the late 1990s. Together, we've agreed to cut the deficit by more than $2 trillion. And we've put in place new rules to hold Wall Street accountable, so a crisis like this never happens again. (Applause.)

The state of our Union is getting stronger. And we've come too far to turn back now. As long as I'm President, I will work with anyone in this chamber to build on this momentum. But I intend to fight obstruction with action, and I will oppose any effort to return to the very same policies that brought on this economic crisis in the first place. (Applause.)

No, we will not go back to an economy weakened by outsourcing, bad debt, and phony financial profits. Tonight, I want to speak about how we move forward, and lay out a blueprint for an economy that's built to last — an economy built on American manufacturing, American energy, skills for American workers, and a renewal of American values.

Now, this blueprint begins with American manufacturing.

On the day I took office, our auto industry was on the verge of collapse. Some even said we should let it die. With a million jobs at stake, I refused to let that happen. In exchange for help, we demanded responsibility. We got workers and automakers to settle their differences. We got the industry to retool and restructure. Today, General Motors is back on top as the world's number-one automaker. (Applause.) Chrysler has grown faster in the U.S. than any major car company. Ford is investing billions in U.S. plants and factories. And together, the entire industry added nearly 160,000 jobs.

We bet on American workers. We bet on American ingenuity. And tonight, the American auto industry is back. (Applause.)

What's happening in Detroit can happen in other industries. It can happen in Cleveland and Pittsburgh and Raleigh. We can't bring every job back that's left our shore. But right now, it's getting more expensive to do business in places like China. Meanwhile, America is more productive. A few weeks ago, the CEO of Master Lock told me that it now makes business sense for him to bring jobs back home. (Applause.) Today, for the first time in 15 years, Master Lock's unionized plant in Milwaukee is running at full capacity. (Applause.)

So we have a huge opportunity, at this moment, to bring manufacturing back. But we have to seize it. Tonight, my message to business leaders is simple: Ask yourselves what you can do to bring jobs back to your country, and your country will do everything we can to help you succeed. (Applause.)

We should start with our tax code. Right now, companies get tax breaks for moving jobs and profits overseas. Meanwhile, companies that choose to stay in America get hit with one of the highest tax rates in the world. It makes no sense, and everyone knows it. So let's change it.

First, if you're a business that wants to outsource jobs, you shouldn't get a tax deduction for doing it. (Applause.) That money should be used to cover moving expenses for companies like Master Lock that decide to bring jobs home. (Applause.)

Second, no American company should be able to avoid paying its fair share of taxes by moving jobs and profits overseas. (Applause.) From now on, every multinational company should have to pay a basic minimum tax. And every penny should go towards lowering taxes for companies that choose to stay here and hire here in America. (Applause.)

Third, if you're an American manufacturer, you should get a bigger tax cut. If you're a high-tech manufacturer, we should double the tax deduction you get for making your products here. And if you want to relocate in a community that was hit hard when a factory left town, you should get help financing a new plant, equipment, or training for new workers. (Applause.)

So my message is simple. It is time to stop rewarding businesses that ship jobs overseas, and start rewarding companies that create jobs right here in America. Send me these tax reforms, and I will sign them right away. (Applause.)

We're also making it easier for American businesses to sell products all over the world. Two years ago, I set a goal of doubling U.S. exports over five years. With the bipartisan trade agreements we signed into law, we're on track to meet that goal ahead of schedule. (Applause.) And soon, there will be millions of new customers for American goods in Panama, Colombia, and South Korea. Soon, there will be new cars on the streets of Seoul imported from Detroit, and Toledo, and Chicago. (Applause.)

I will go anywhere in the world to open new markets for American products. And I will not stand by when our competitors don't play by the rules. We've brought trade cases against China at nearly twice the rate as the last administration –- and it's made a difference. (Applause.) Over a thousand Americans are working today because we stopped a surge in Chinese tires. But we need to do more. It's not right when another country lets our movies, music, and software be pirated. It's not fair when foreign manufacturers have a leg up on ours only because they're heavily subsidized.

Tonight, I'm announcing the creation of a Trade Enforcement Unit that will be charged with investigating unfair trading practices in countries like China. (Applause.) There will be more inspections to prevent counterfeit or unsafe goods from crossing our borders. And this Congress should make sure that no foreign company has an advantage over American manufacturing when it comes to accessing financing or new markets like Russia. Our workers are the most productive on Earth, and if the playing field is level, I promise you -– America will always win. (Applause.)

I also hear from many business leaders who want to hire in the United States but can't find workers with the right skills. Growing industries in science and technology have twice as many openings as we have workers who can do the job. Think about that –- openings at a time when millions of Americans are looking for work. It's inexcusable. And we know how to fix it.

Jackie Bray is a single mom from North Carolina who was laid off from her job as a mechanic. Then Siemens opened a gas turbine factory in Charlotte, and formed a partnership with Central Piedmont Community College. The company helped the college design courses in laser and robotics training. It paid Jackie's tuition, then hired her to help operate their plant.

I want every American looking for work to have the same opportunity as Jackie did. Join me in a national commitment to train 2 million Americans with skills that will lead directly to a job. (Applause.) My administration has already lined up more companies that want to help. Model partnerships between businesses like Siemens and community colleges in places like Charlotte, and Orlando, and Louisville are up and running. Now you need to give more community colleges the resources they need to become community career centers -– places that teach people skills that businesses are looking for right now, from data management to high-tech manufacturing.

And I want to cut through the maze of confusing training programs, so that from now on, people like Jackie have one program, one website, and one place to go for all the information and help that they need. It is time to turn our unemployment system into a reemployment system that puts people to work. (Applause.)

These reforms will help people get jobs that are open today. But to prepare for the jobs of tomorrow, our commitment to skills and education has to start earlier.

For less than 1 percent of what our nation spends on education each year, we've convinced nearly every state in the country to raise their standards for teaching and learning -- the first time that's happened in a generation.

But challenges remain. And we know how to solve them.

At a time when other countries are doubling down on education, tight budgets have forced states to lay off thousands of teachers. We know a good teacher can increase the lifetime income of a classroom by over $250,000. A great teacher can offer an escape from poverty to the child who dreams beyond his circumstance. Every person in this chamber can point to a teacher who changed the trajectory of their lives. Most teachers work tirelessly, with modest pay, sometimes digging into their own pocket for school supplies -- just to make a difference.

Teachers matter. So instead of bashing them, or defending the status quo, let's offer schools a deal. Give them the resources to keep good teachers on the job, and reward the best ones. (Applause.) And in return, grant schools flexibility: to teach with creativity and passion; to stop teaching to the test; and to replace teachers who just aren't helping kids learn. That's a bargain worth making. (Applause.)

We also know that when students don't walk away from their education, more of them walk the stage to get their diploma. When students are not allowed to drop out, they do better. So tonight, I am proposing that every state -- every state -- requires that all students stay in high school until they graduate or turn 18. (Applause.)

When kids do graduate, the most daunting challenge can be the cost of college. At a time when Americans owe more in tuition debt than credit card debt, this Congress needs to stop the interest rates on student loans from doubling in July. (Applause.)

Extend the tuition tax credit we started that saves millions of middle-class families thousands of dollars, and give more young people the chance to earn their way through college by doubling the number of work-study jobs in the next five years. (Applause.)

Of course, it's not enough for us to increase student aid. We can't just keep subsidizing skyrocketing tuition; we'll run out of money. States also need to do their part, by making higher education a higher priority in their budgets. And colleges and universities have to do their part by working to keep costs down.

Recently, I spoke with a group of college presidents who've done just that. Some schools redesign courses to help students finish more quickly. Some use better technology. The point is, it's possible. So let me put colleges and universities on notice: If you can't stop tuition from going up, the funding you get from taxpayers will go down. (Applause.) Higher education can't be a luxury -– it is an economic imperative that every family in America should be able to afford.

Let's also remember that hundreds of thousands of talented, hardworking students in this country face another challenge: the fact that they aren't yet American citizens. Many were brought here as small children, are American through and through, yet they live every day with the threat of deportation. Others came more recently, to study business and science and engineering, but as soon as they get their degree, we send them home to invent new products and create new jobs somewhere else.

That doesn't make sense.

I believe as strongly as ever that we should take on illegal immigration. That's why my administration has put more boots on the border than ever before. That's why there are fewer illegal crossings than when I took office. The opponents of action are out of excuses. We should be working on comprehensive immigration reform right now. (Applause.)

But if election-year politics keeps Congress from acting on a comprehensive plan, let's at least agree to stop expelling responsible young people who want to staff our labs, start new businesses, defend this country. Send me a law that gives them the chance to earn their citizenship. I will sign it right away. (Applause.)

You see, an economy built to last is one where we encourage the talent and ingenuity of every person in this country. That means women should earn equal pay for equal work. (Applause.) It means we should support everyone who's willing to work, and every risk-taker and entrepreneur who aspires to become the next Steve Jobs.

After all, innovation is what America has always been about. Most new jobs are created in start-ups and small businesses. So let's pass an agenda that helps them succeed. Tear down regulations that prevent aspiring entrepreneurs from getting the financing to grow. (Applause.) Expand tax relief to small businesses that are raising wages and creating good jobs. Both parties agree on these ideas. So put them in a bill, and get it on my desk this year. (Applause.)

Innovation also demands basic research. Today, the discoveries taking place in our federally financed labs and universities could lead to new treatments that kill cancer cells but leave healthy ones untouched. New lightweight vests for cops and soldiers that can stop any bullet. Don't gut these investments in our budget. Don't let other countries win the race for the future. Support the same kind of research and innovation that led to the computer chip and the Internet; to new American jobs and new American industries.

And nowhere is the promise of innovation greater than in American-made energy. Over the last three years, we've opened millions of new acres for oil and gas exploration, and tonight, I'm directing my administration to open more than 75 percent of our potential offshore oil and gas resources. (Applause.) Right now -- right now -- American oil production is the highest that it's been in eight years. That's right -- eight years. Not only that -- last year, we relied less on foreign oil than in any of the past 16 years. (Applause.)

But with only 2 percent of the world's oil reserves, oil isn't enough. This country needs an all-out, all-of-the-above strategy that develops every available source of American energy. (Applause.) A strategy that's cleaner, cheaper, and full of new jobs.

We have a supply of natural gas that can last America nearly 100 years. (Applause.) And my administration will take every possible action to safely develop this energy. Experts believe this will support more than 600,000 jobs by the end of the decade. And I'm requiring all companies that drill for gas on public lands to disclose the chemicals they use. (Applause.) Because America will develop this resource without putting the health and safety of our citizens at risk.

The development of natural gas will create jobs and power trucks and factories that are cleaner and cheaper, proving that we don't have to choose between our environment and our economy. (Applause.) And by the way, it was public research dollars, over the course of 30 years, that helped develop the technologies to extract all this natural gas out of shale rock -– reminding us that government support is critical in helping businesses get new energy ideas off the ground. (Applause.)

Now, what's true for natural gas is just as true for clean energy. In three years, our partnership with the private sector has already positioned America to be the world's leading manufacturer of high-tech batteries. Because of federal investments, renewable energy use has nearly doubled, and thousands of Americans have jobs because of it.

When Bryan Ritterby was laid off from his job making furniture, he said he worried that at 55, no one would give him a second chance. But he found work at Energetx, a wind turbine manufacturer in Michigan. Before the recession, the factory only made luxury yachts. Today, it's hiring workers like Bryan, who said, "I'm proud to be working in the industry of the future."

Our experience with shale gas, our experience with natural gas, shows us that the payoffs on these public investments don't always come right away. Some technologies don't pan out; some companies fail. But I will not walk away from the promise of clean energy. I will not walk away from workers like Bryan. (Applause.) I will not cede the wind or solar or battery industry to China or Germany because we refuse to make the same commitment here.

We've subsidized oil companies for a century. That's long enough. (Applause.) It's time to end the taxpayer giveaways to an industry that rarely has been more profitable, and double-down on a clean energy industry that never has been more promising. Pass clean energy tax credits. Create these jobs. (Applause.)

We can also spur energy innovation with new incentives. The differences in this chamber may be too deep right now to pass a comprehensive plan to fight climate change. But there's no reason why Congress shouldn't at least set a clean energy standard that creates a market for innovation. So far, you haven't acted. Well, tonight, I will. I'm directing my administration to allow the development of clean energy on enough public land to power 3 million homes. And I'm proud to announce that the Department of Defense, working with us, the world's largest consumer of energy, will make one of the largest commitments to clean energy in history -– with the Navy purchasing enough capacity to power a quarter of a million homes a year. (Applause.)

Of course, the easiest way to save money is to waste less energy. So here's a proposal: Help manufacturers eliminate energy waste in their factories and give businesses incentives to upgrade their buildings. Their energy bills will be $100 billion lower over the next decade, and America will have less pollution, more manufacturing, more jobs for construction workers who need them. Send me a bill that creates these jobs. (Applause.)

Building this new energy future should be just one part of a broader agenda to repair America's infrastructure. So much of America needs to be rebuilt. We've got crumbling roads and bridges; a power grid that wastes too much energy; an incomplete high-speed broadband network that prevents a small business owner in rural America from selling her products all over the world.

During the Great Depression, America built the Hoover Dam and the Golden Gate Bridge. After World War II, we connected our states with a system of highways. Democratic and Republican administrations invested in great projects that benefited everybody, from the workers who built them to the businesses that still use them today.

In the next few weeks, I will sign an executive order clearing away the red tape that slows down too many construction projects. But you need to fund these projects. Take the money we're no longer spending at war, use half of it to pay down our debt, and use the rest to do some nation-building right here at home. (Applause.)

There's never been a better time to build, especially since the construction industry was one of the hardest hit when the housing bubble burst. Of course, construction workers weren't the only ones who were hurt. So were millions of innocent Americans who've seen their home values decline. And while government can't fix the problem on its own, responsible homeowners shouldn't have to sit and wait for the housing market to hit bottom to get some relief.

And that's why I'm sending this Congress a plan that gives every responsible homeowner the chance to save about $3,000 a year on their mortgage, by refinancing at historically low rates. (Applause.) No more red tape. No more runaround from the banks. A small fee on the largest financial institutions will ensure that it won't add to the deficit and will give those banks that were rescued by taxpayers a chance to repay a deficit of trust. (Applause.)

Let's never forget: Millions of Americans who work hard and play by the rules every day deserve a government and a financial system that do the same. It's time to apply the same rules from top to bottom. No bailouts, no handouts, and no copouts. An America built to last insists on responsibility from everybody.

We've all paid the price for lenders who sold mortgages to people who couldn't afford them, and buyers who knew they couldn't afford them. That's why we need smart regulations to prevent irresponsible behavior. (Applause.) Rules to prevent financial fraud or toxic dumping or faulty medical devices -- these don't destroy the free market. They make the free market work better.

There's no question that some regulations are outdated, unnecessary, or too costly. In fact, I've approved fewer regulations in the first three years of my presidency than my Republican predecessor did in his. (Applause.) I've ordered every federal agency to eliminate rules that don't make sense. We've already announced over 500 reforms, and just a fraction of them will save business and citizens more than $10 billion over the next five years. We got rid of one rule from 40 years ago that could have forced some dairy farmers to spend $10,000 a year proving that they could contain a spill -- because milk was somehow classified as an oil. With a rule like that, I guess it was worth crying over spilled milk. (Laughter and applause.)

Now, I'm confident a farmer can contain a milk spill without a federal agency looking over his shoulder. (Applause.) Absolutely. But I will not back down from making sure an oil company can contain the kind of oil spill we saw in the Gulf two years ago. (Applause.) I will not back down from protecting our kids from mercury poisoning, or making sure that our food is safe and our water is clean. I will not go back to the days when health insurance companies had unchecked power to cancel your policy, deny your coverage, or charge women differently than men. (Applause.)

And I will not go back to the days when Wall Street was allowed to play by its own set of rules. The new rules we passed restore what should be any financial system's core purpose: Getting funding to entrepreneurs with the best ideas, and getting loans to responsible families who want to buy a home, or start a business, or send their kids to college.

So if you are a big bank or financial institution, you're no longer allowed to make risky bets with your customers' deposits. You're required to write out a "living will" that details exactly how you'll pay the bills if you fail –- because the rest of us are not bailing you out ever again. (Applause.) And if you're a mortgage lender or a payday lender or a credit card company, the days of signing people up for products they can't afford with confusing forms and deceptive practices -- those days are over. Today, American consumers finally have a watchdog in Richard Cordray with one job: To look out for them. (Applause.)

We'll also establish a Financial Crimes Unit of highly trained investigators to crack down on large-scale fraud and protect people's investments. Some financial firms violate major anti-fraud laws because there's no real penalty for being a repeat offender. That's bad for consumers, and it's bad for the vast majority of bankers and financial service professionals who do the right thing. So pass legislation that makes the penalties for fraud count.

And tonight, I'm asking my Attorney General to create a special unit of federal prosecutors and leading state attorney general to expand our investigations into the abusive lending and packaging of risky mortgages that led to the housing crisis. (Applause.) This new unit will hold accountable those who broke the law, speed assistance to homeowners, and help turn the page on an era of recklessness that hurt so many Americans.

Now, a return to the American values of fair play and shared responsibility will help protect our people and our economy. But it should also guide us as we look to pay down our debt and invest in our future.

Right now, our most immediate priority is stopping a tax hike on 160 million working Americans while the recovery is still fragile. (Applause.) People cannot afford losing $40 out of each paycheck this year. There are plenty of ways to get this done. So let's agree right here, right now: No side issues. No drama. Pass the payroll tax cut without delay. Let's get it done. (Applause.)

When it comes to the deficit, we've already agreed to more than $2 trillion in cuts and savings. But we need to do more, and that means making choices. Right now, we're poised to spend nearly $1 trillion more on what was supposed to be a temporary tax break for the wealthiest 2 percent of Americans. Right now, because of loopholes and shelters in the tax code, a quarter of all millionaires pay lower tax rates than millions of middle-class households. Right now, Warren Buffett pays a lower tax rate than his secretary.

Do we want to keep these tax cuts for the wealthiest Americans? Or do we want to keep our investments in everything else –- like education and medical research; a strong military and care for our veterans? Because if we're serious about paying down our debt, we can't do both.

The American people know what the right choice is. So do I. As I told the Speaker this summer, I'm prepared to make more reforms that rein in the long-term costs of Medicare and Medicaid, and strengthen Social Security, so long as those programs remain a guarantee of security for seniors.

But in return, we need to change our tax code so that people like me, and an awful lot of members of Congress, pay our fair share of taxes. (Applause.)

Tax reform should follow the Buffett Rule. If you make more than $1 million a year, you should not pay less than 30 percent in taxes. And my Republican friend Tom Coburn is right: Washington should stop subsidizing millionaires. In fact, if you're earning a million dollars a year, you shouldn't get special tax subsidies or deductions. On the other hand, if you make under $250,000 a year, like 98 percent of American families, your taxes shouldn't go up. (Applause.) You're the ones struggling with rising costs and stagnant wages. You're the ones who need relief.

Now, you can call this class warfare all you want. But asking a billionaire to pay at least as much as his secretary in taxes? Most Americans would call that common sense.

We don't begrudge financial success in this country. We admire it. When Americans talk about folks like me paying my fair share of taxes, it's not because they envy the rich. It's because they understand that when I get a tax break I don't need and the country can't afford, it either adds to the deficit, or somebody else has to make up the difference -- like a senior on a fixed income, or a student trying to get through school, or a family trying to make ends meet. That's not right. Americans know that's not right. They know that this generation's success is only possible because past generations felt a responsibility to each other, and to the future of their country, and they know our way of life will only endure if we feel that same sense of shared responsibility. That's how we'll reduce our deficit. That's an America built to last. (Applause.)

Now, I recognize that people watching tonight have differing views about taxes and debt, energy and health care. But no matter what party they belong to, I bet most Americans are thinking the same thing right about now: Nothing will get done in Washington this year, or next year, or maybe even the year after that, because Washington is broken.

Can you blame them for feeling a little cynical?

The greatest blow to our confidence in our economy last year didn't come from events beyond our control. It came from a debate in Washington over whether the United States would pay its bills or not. Who benefited from that fiasco?

I've talked tonight about the deficit of trust between Main Street and Wall Street. But the divide between this city and the rest of the country is at least as bad -- and it seems to get worse every year.

Some of this has to do with the corrosive influence of money in politics. So together, let's take some steps to fix that. Send me a bill that bans insider trading by members of Congress; I will sign it tomorrow. (Applause.) Let's limit any elected official from owning stocks in industries they impact. Let's make sure people who bundle campaign contributions for Congress can't lobby Congress, and vice versa -- an idea that has bipartisan support, at least outside of Washington.

Some of what's broken has to do with the way Congress does its business these days. A simple majority is no longer enough to get anything -– even routine business –- passed through the Senate. (Applause.) Neither party has been blameless in these tactics. Now both parties should put an end to it. (Applause.) For starters, I ask the Senate to pass a simple rule that all judicial and public service nominations receive a simple up or down vote within 90 days. (Applause.)

The executive branch also needs to change. Too often, it's inefficient, outdated and remote. (Applause.) That's why I've asked this Congress to grant me the authority to consolidate the federal bureaucracy, so that our government is leaner, quicker, and more responsive to the needs of the American people. (Applause.)

Finally, none of this can happen unless we also lower the temperature in this town. We need to end the notion that the two parties must be locked in a perpetual campaign of mutual destruction; that politics is about clinging to rigid ideologies instead of building consensus around common-sense ideas.

I'm a Democrat. But I believe what Republican Abraham Lincoln believed: That government should do for people only what they cannot do better by themselves, and no more. (Applause.) That's why my education reform offers more competition, and more control for schools and states. That's why we're getting rid of regulations that don't work. That's why our health care law relies on a reformed private market, not a government program.

On the other hand, even my Republican friends who complain the most about government spending have supported federally financed roads, and clean energy projects, and federal offices for the folks back home.

The point is, we should all want a smarter, more effective government. And while we may not be able to bridge our biggest philosophical differences this year, we can make real progress. With or without this Congress, I will keep taking actions that help the economy grow. But I can do a whole lot more with your help. Because when we act together, there's nothing the United States of America can't achieve. (Applause.) That's the lesson we've learned from our actions abroad over the last few years.

Ending the Iraq war has allowed us to strike decisive blows against our enemies. From Pakistan to Yemen, the al Qaeda operatives who remain are scrambling, knowing that they can't escape the reach of the United States of America. (Applause.)

From this position of strength, we've begun to wind down the war in Afghanistan. Ten thousand of our troops have come home. Twenty-three thousand more will leave by the end of this summer. This transition to Afghan lead will continue, and we will build an enduring partnership with Afghanistan, so that it is never again a source of attacks against America. (Applause.)

As the tide of war recedes, a wave of change has washed across the Middle East and North Africa, from Tunis to Cairo; from Sana'a to Tripoli. A year ago, Qaddafi was one of the world's longest-serving dictators -– a murderer with American blood on his hands. Today, he is gone. And in Syria, I have no doubt that the Assad regime will soon discover that the forces of change cannot be reversed, and that human dignity cannot be denied. (Applause.)

How this incredible transformation will end remains uncertain. But we have a huge stake in the outcome. And while it's ultimately up to the people of the region to decide their fate, we will advocate for those values that have served our own country so well. We will stand against violence and intimidation. We will stand for the rights and dignity of all human beings –- men and women; Christians, Muslims and Jews. We will support policies that lead to strong and stable democracies and open markets, because tyranny is no match for liberty.

And we will safeguard America's own security against those who threaten our citizens, our friends, and our interests. Look at Iran. Through the power of our diplomacy, a world that was once divided about how to deal with Iran's nuclear program now stands as one. The regime is more isolated than ever before; its leaders are faced with crippling sanctions, and as long as they shirk their responsibilities, this pressure will not relent.

Let there be no doubt: America is determined to prevent Iran from getting a nuclear weapon, and I will take no options off the table to achieve that goal. (Applause.)

But a peaceful resolution of this issue is still possible, and far better, and if Iran changes course and meets its obligations, it can rejoin the community of nations.

The renewal of American leadership can be felt across the globe. Our oldest alliances in Europe and Asia are stronger than ever. Our ties to the Americas are deeper. Our ironclad commitment -- and I mean ironclad -- to Israel's security has meant the closest military cooperation between our two countries in history. (Applause.)

We've made it clear that America is a Pacific power, and a new beginning in Burma has lit a new hope. From the coalitions we've built to secure nuclear materials, to the missions we've led against hunger and disease; from the blows we've dealt to our enemies, to the enduring power of our moral example, America is back.

Anyone who tells you otherwise, anyone who tells you that America is in decline or that our influence has waned, doesn't know what they're talking about. (Applause.)

That's not the message we get from leaders around the world who are eager to work with us. That's not how people feel from Tokyo to Berlin, from Cape Town to Rio, where opinions of America are higher than they've been in years. Yes, the world is changing. No, we can't control every event. But America remains the one indispensable nation in world affairs –- and as long as I'm President, I intend to keep it that way. (Applause.)

That's why, working with our military leaders, I've proposed a new defense strategy that ensures we maintain the finest military in the world, while saving nearly half a trillion dollars in our budget. To stay one step ahead of our adversaries, I've already sent this Congress legislation that will secure our country from the growing dangers of cyber-threats. (Applause.)

Above all, our freedom endures because of the men and women in uniform who defend it. (Applause.) As they come home, we must serve them as well as they've served us. That includes giving them the care and the benefits they have earned –- which is why we've increased annual VA spending every year I've been President. (Applause.) And it means enlisting our veterans in the work of rebuilding our nation.

With the bipartisan support of this Congress, we're providing new tax credits to companies that hire vets. Michelle and Jill Biden have worked with American businesses to secure a pledge of 135,000 jobs for veterans and their families. And tonight, I'm proposing a Veterans Jobs Corps that will help our communities hire veterans as cops and firefighters, so that America is as strong as those who defend her. (Applause.)

Which brings me back to where I began. Those of us who've been sent here to serve can learn a thing or two from the service of our troops. When you put on that uniform, it doesn't matter if you're black or white; Asian, Latino, Native American; conservative, liberal; rich, poor; gay, straight. When you're marching into battle, you look out for the person next to you, or the mission fails. When you're in the thick of the fight, you rise or fall as one unit, serving one nation, leaving no one behind.

One of my proudest possessions is the flag that the SEAL Team took with them on the mission to get bin Laden. On it are each of their names. Some may be Democrats. Some may be Republicans. But that doesn't matter. Just like it didn't matter that day in the Situation Room, when I sat next to Bob Gates -- a man who was George Bush's defense secretary -- and Hillary Clinton -- a woman who ran against me for president.

All that mattered that day was the mission. No one thought about politics. No one thought about themselves. One of the young men involved in the raid later told me that he didn't deserve credit for the mission. It only succeeded, he said, because every single member of that unit did their job -- the pilot who landed the helicopter that spun out of control; the translator who kept others from entering the compound; the troops who separated the women and children from the fight; the SEALs who charged up the stairs. More than that, the mission only succeeded because every member of that unit trusted each other -- because you can't charge up those stairs, into darkness and danger, unless you know that there's somebody behind you, watching your back.

So it is with America. Each time I look at that flag, I'm reminded that our destiny is stitched together like those 50 stars and those 13 stripes. No one built this country on their own. This nation is great because we built it together. This nation is great because we worked as a team. This nation is great because we get each other's backs. And if we hold fast to that truth, in this moment of trial, there is no challenge too great; no mission too hard. As long as we are joined in common purpose, as long as we maintain our common resolve, our journey moves forward, and our future is hopeful, and the state of our Union will always be strong.

Thank you, God bless you, and God bless the United States of America. (Applause.)

END
10:16 P.M. EST

Learn more

- Take a deep dive into the data behind the President's plan
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The White House

Office of the Press Secretary

For Immediate Release December 10, 2012

Remarks by the President at the Daimler Detroit Diesel Plant, Redford, MI

Daimler Detroit Diesel Plant
Redford, Michigan

2:29 P.M. EST

THE PRESIDENT: Hello, Redford! (Applause.) It is good to be back in Michigan. (Applause.) How is everybody doing today? (Applause.)

Now, let me just start off by saying we have something in common -- both our teams lost yesterday. (Laughter.) I mean, I would like to come here and talk a little smack about the Bears, but we didn't quite get it done. But it is wonderful to be back. It is good to see everybody in the great state of Michigan. (Applause.)

A few people I want to acknowledge -- first of all, the Mayor of Detroit here -- Dave Bing is in the house. (Applause.) We've got the Redford Supervisor -- Tracey Schultz Kobylarz. (Applause.) We've got some outstanding members of Congress who are here -- please give them a big round of applause. (Applause.)

I want to thank Martin for hosting us. I want to thank Jeff and Gibby for giving me a great tour of the factory. (Applause.) I've got to say I love coming to factories.

AUDIENCE MEMBER: I love you!

THE PRESIDENT: I love you. (Applause.)

So in addition to seeing the best workers in the world -- (applause) -- you've also got all this cool equipment. (Laughter.) I wanted to try out some of the equipment, but Secret Service wouldn't let me. (Laughter.) They said, you're going to drop something on your head, hurt yourself. (Laughter.) They were worried I'd mess something up. And Jeff and Gibby may not admit it, but I think they were pretty happy the Secret Service wouldn't let me touch the equipment. (Laughter.)

Now, it's been a little over a month since the election came to an end. (Applause.) So it's now safe for you to turn your televisions back on. (Laughter.) All those scary political ads are off the air. You can answer your phone again -- nobody is calling you in the middle of dinner asking for your support. But, look, I have to admit there's one part of the campaign that I miss, and that is it is a great excuse for me to get out of Washington and come to towns like this and talk to the people who work so hard every day and are looking out for their families and are in their communities, and just having a conversation about what kind of country do we want to be; what kind of country do we want to leave behind for our kids. Because ultimately, that's what this is about.

And I believe -- and I've been saying this not just for the last six months or the last year, but ever since I got into public office -- I believe America only succeeds and thrives when we've got a strong and growing middle class. (Applause.) That's what I believe. I believe we're at our best when everybody who works hard has a chance to get ahead; that they can get a job that pays the bills; that they've got health care that they can count on; that they can retire with dignity and respect, maybe take a vacation once in a while -- nothing fancy, just being able to pack up the kids and go someplace and enjoy time with people that you love; make sure that your kids can go to a good school; make sure they can aspire to whatever they want to be.

That idea is what built America. That's the idea that built Michigan. That's the idea that's at the heart of the economic plan I've been talking about all year long on the campaign trail. I want to give more Americans the chance to earn the skills that businesses are looking for right now, and give our kids the kind of education they need to succeed in the 21st century. I want to make sure America leads the world in research and technology and clean energy. I want to put people back to work rebuilding our roads and our bridges and our schools. (Applause.) That's how we grow an economy.

WATCH THE VIDEO

December 10, 2012 9:12 PM

President Obama Speaks on the Economy and Middle-Class Tax Cuts

BLOG POSTS ON THIS ISSUE

January 23, 2013 12:45 PM EST

Fireside Hangouts: Vice President Biden Joins a Conversation on Reducing Gun Violence

On Thursday, January 24 at 1:45 p.m. ET, Vice President Biden will host the latest "Fireside Hangout" – a 21st century take on FDR's famous radio addresses – to talk about reducing gun violence.

January 23, 2013 10:40 AM EST

Surprise! President and Mrs. Obama Greet White House Tour (Bo Was There, Too)

The President and First Lady welcomed the guests with handshakes, hugs and even fistbumps, and Bo was treated to a near-constant stream of affectionate pats and petting.

January 21, 2013 3:26 PM EST

Be a Part of the Next Four Years

The President's second term will offer many ways

I want us to bring down our deficits, but I want to do it in a balanced, responsible way. And I want to reward -- I want a tax code that rewards businesses and manufacturers like Detroit Diesel right here, creating jobs right here in Redford, right here in Michigan, right here in the United States of America. (Applause.) That's where we need to go. That's the country we need to build. And when it comes to bringing manufacturing back to America -- that's why I'm here today.

Since 1938, Detroit Diesel has been turning out some of the best engines in the world. (Applause.) Over all those years, generations of Redford workers have walked through these doors. Not just to punch a clock. Not just to pick up a paycheck. Not just to build an engine. But to build a middle-class life for their families; to earn a shot at the American Dream.

For seven and a half decades, through good times and bad, through revolutions in technology that sent a lot of good jobs -- manufacturing jobs -- overseas, men and women like you, your parents, maybe even your grandparents, have done your part to build up America's manufacturing strength. That's something you can all be proud of. And now you're writing a new proud chapter to that history. Eight years ago, you started building axles here alongside the engines. That meant more work. That meant more jobs. (Applause.) So you started seeing products -- more products stamped with those three proud words: Made in America.
Today, Daimler is announcing a new $120 million investment into this plant, creating 115 good, new union jobs building transmissions and turbochargers right here in Redford -- (applause) -- 115 good new jobs right here in this plant, making things happen. That is great for the plant. It's great for this community. But it's also good for American manufacturing. Soon, you guys will be building all the key parts that go into powering a heavy-duty truck, all at the same facility. Nobody else in America is doing that. Nobody else in North America is doing that.

And by putting everything together in one place, under one roof, Daimler engineers can design each part so it works better with the others. That means greater fuel efficiency for your trucks. It means greater savings for your customers. That's a big deal. And it's just the latest example of Daimler's leadership on this issue.

Last year, I was proud to have your support when we announced the first-ever national fuel-efficiency standards for commercial trucks, which is going to help save consumers money and reduce our dependence on foreign oil. That's good news. (Applause.)

But here's the other reason why what you guys are doing, what Daimler is doing, is so important. For a long time, companies, they weren't always making those kinds of investments here in the United States. They weren't always investing in American workers. They certainly weren't willing to make them in the U.S. auto industry.

Remember, it was just a few years ago that our auto industry was on the verge of collapse. GM, Chrysler were all on the brink of failure. And if they failed, the suppliers and distributors that get their business from those companies, they would have died off, too. Even Ford could have gone down -- production halted. Factories shuttered. Once proud companies chopped up and sold off for scraps. And all of you -- the men and women who built these companies with your own hands -- would have been hung out to dry. And everybody in this community that depends on you -- restaurant owners, storekeepers, bartenders -- (laughter and applause) -- their livelihoods would have been at stake, too.

So I wasn't about to let that happen. I placed my bet on American workers. We bet on American ingenuity. I'd make that same bet any day of the week. (Applause.) Three and a half years later, that bet is paying off. This industry has added over a quarter of a million new jobs. Assembly lines are humming again. The American auto industry is back.

And companies like Daimler know you're still a smart bet. They could have made their investment somewhere else, but they didn't. And if you ask them whether it was a tough call, they'll tell you it wasn't even close. So the word is going out all around the world: If you want to find the best workers in the world, if you want to find the best factories in the world, if you want to build the best cars or trucks or any other product in the world, you should invest in the United States of America. This is the place to be. (Applause.)

See, you're starting to see the competitive balance is tipping a little bit. Over the past few years, it's become more expensive to do business in countries like China. Our workers have become even more productive. Our energy costs are starting to go down here in the United States. And we still have the largest market. So when you factor in everything, it makes sense to invest here, in America.

And that's one of the reasons why American manufacturing is growing at the fastest pace since the 1990s. And thanks in part to that boost in manufacturing, four years after the worst economic crisis of our lifetimes, our economy is growing again. Our businesses have created more than 5.5 million new jobs over the past 33 months. So we're making progress. (Applause.) We're moving in the right direction. We're going forward.

So what we need to do is simple. We need to keep going. We need to keep going forward. We should do everything we can to keep creating good middle-class jobs that help folks rebuild security for their families. (Applause.) And we should do everything we can to encourage companies like Daimler to keep investing in American workers.

And by the way, what we shouldn't do -- I just got to say this -- what we shouldn't be doing is trying to take away your rights to bargain for better wages and working conditions. (Applause.) We shouldn't be doing that. (Applause.) These so-called "right to work" laws, they don't have to do with economics; they have everything to do with politics. (Applause.) What they're really talking about is giving you the right to work for less money. (Applause.)

You only have to look to Michigan -- where workers were instrumental in reviving the auto industry -- to see how unions have helped build not just a stronger middle class but a stronger America. (Applause.) So folks from our state's capital, all the way to the nation's capital, they should be focused on the same thing. They should be working to make sure companies like this manufacturer is able to make more great products. That's what they should be focused on. (Applause.) We don't want a race to the bottom. We want a race to the top. (Applause.)

America is not going to compete based on low-skill, low-wage, no workers' rights. That's not our competitive advantage. There's always going to be some other country that can treat its workers even worse. Right?

AUDIENCE: Right!

THE PRESIDENT: What's going to make us succeed is we got the best workers -- well trained, reliable, productive, low turnover, healthy. That's what makes us strong. And it also is what allows our workers then to buy the products that we make because they got enough money in their pockets. (Applause.)

So we've got to get past this whole situation where we manufacture crises because of politics. That actually leads to less certainty, more conflict, and we can't all focus on coming together to grow.

AUDIENCE MEMBER: That's right!

THE PRESIDENT: And the same thing -- we're seeing the same thing in Washington. I'm sure you've all heard the talk recently about some big deadlines we're facing in a few weeks when it comes to decisions on jobs and investment and taxes. And that debate is going to have a big impact on all of you. Some of you may know this: If Congress doesn't act soon, meaning in the next few weeks, starting on January 1st, everybody is going to see their income taxes go up.

AUDIENCE: No!

THE PRESIDENT: It's true. You all don't like that.

AUDIENCE: No!

THE PRESIDENT: Typical, middle-class family of four will see an income tax hike of around $2,200. How many of you can afford to pay another $2,200 in taxes? Not you?

AUDIENCE: No!

THE PRESIDENT: I didn't think so. You can't afford to lose that money. That's a hit you can't afford to take. And, by the way, that's not a good hit for businesses, either -- because if Congress lets middle-class taxes go up, economists will tell you that means people will spend nearly $200 billion less than they otherwise would spend. Consumer spending is going to go down. That means you've got less customers. Businesses get fewer profits. They hire fewer workers. You go in a downward spiral. Wrong idea.

Here is the good news: We can solve this problem. All Congress needs to do is pass a law that would prevent a tax hike on the first $250,000 of everybody's income -- everybody. (Applause.) That means 98 percent of Americans -- and probably 100 percent of you -- (laughter) -- 97 percent of small businesses wouldn't see their income taxes go up a single dime. Even the wealthiest Americans would still get a tax cut on the first $250,000 of their income. But when they start making a million, or $10 million, or $20 million you can afford to pay a little bit more. (Applause.) You're not too strapped.

So Congress can do that right now. Everybody says they agree with it. Let's get it done. (Applause.)

So that's the bare minimum. That's the bare minimum we should be doing in order to the grow the economy. But we can do more. We can do more than just extend middle-class tax cuts. I've said I will work with Republicans on a plan for economic growth, job creation, and reducing our deficits. And that has some compromise between Democrats and Republicans. I understand people have a lot of different views. I'm willing to compromise a little bit.

But if we're serious about reducing our deficit, we've also got to be serious about investing in the things that help us grow and make the middle class strong, like education, and research and development, and making sure kids can go to college, and rebuilding our roads and our infrastructure. (Applause.) We've got to do that.

So when you put it all together, what you need is a package that keeps taxes where they are for middle-class families; we make some tough spending cuts on things that we don't need; and then we ask the wealthiest

Americans to pay a slightly higher tax rate. And that's a principle I won't compromise on, because I'm not going to have a situation where the wealthiest among us, including folks like me, get to keep all our tax breaks, and then we're asking students to pay higher student loans. Or suddenly, a school doesn't have schoolbooks because the school district couldn't afford it. Or some family that has a disabled kid isn't getting the help that they need through Medicaid.

We're not going to do that. We're not going to make that tradeoff. That's not going to help us to grow. Our economic success has never come from the top down; it comes from the middle out. It comes from the bottom up. (Applause.) It comes from folks like you working hard, and if you're working hard and you're successful, then you become customers and everybody does well.

Our success as a country in this new century will be defined by how well we educate our kids, how well we train our workers, how well we invent, how well we innovate, how well we build things like cars and engines -- all the things that helped create the greatest middle class the world has ever known. That's how you bring new jobs back to Detroit. That's how you bring good jobs back to America. That's what I'm focused on. That's what I will stay relentlessly focused on going forward. (Applause.)

Because when we focus on these things –- when we stay true to ourselves and our history, there's nothing we can't do. (Applause.) And if you don't believe me, you need to come down to this plant and see all these outstanding workers.

In fact, as I was coming over here, I was hearing about a guy named Willie. (Applause.) Where's Willie? There's Willie right here. There's Willie. (Applause.) Now, in case you haven't heard of him, they actually call him "Pretty Willie." (Laughter.) Now, I got to say you got to be pretty tough to have a nickname like "Pretty Willie." (Laughter.) He's tough.

On Wednesday, Willie will celebrate 60 years working at Detroit Diesel -- 60 years. (Applause.) Willie started back on December 12, 1952. I was not born yet. (Laughter.) Wasn't even close to being born. He made $1.40 an hour. The only time he spent away from this plant was when he was serving our country in the Korean War. (Applause.) So three generations of Willie's family have passed through Detroit Diesel. One of his daughters works here with him right now -- is that right? There she is. (Applause.)

In all his years, Willie has been late to work only once. It was back in 1977. (Laughter.) It's been so long he can't remember why he was late -- (laughter and applause) -- but we're willing to give him a pass.

So Willie believes in hard work. You don't keep a job for 60 years if you don't work hard. Sooner or later, someone is going to fire you if you don't work hard. He takes pride in being part of something bigger than himself. He's committed to family; he's committed to community; he's committed to country. That's how Willie lives his life. That's how all of you live your lives.

And that makes me hopeful about the future, because you're out there fighting every day for a better future for your family and your country. And when you do that, that means you're creating value all across this economy. You're inspiring people. You're being a good example for your kids. That's what makes America great. That's what we have to stay focused on.

And as long as I've got the privilege of serving as your President, I'm going to keep fighting for you. I'm going to keep fighting for your kids. I'm going to keep fighting for an America where anybody, no matter who you are, no matter what you look like, no matter where you come from, you can make it if you try here in America. (Applause.)

Thank you very much, everybody. God bless you. (Applause.)

END
2:51 P.M. EST

Remarks of President Barack Obama – As Prepared for Delivery
Address to Joint Session of Congress
Tuesday, February 24th, 2009

(en español)

Madame Speaker, Mr. Vice President, Members of Congress, and the First Lady of the United States:

I've come here tonight not only to address the distinguished men and women in this great chamber, but to speak frankly and directly to the men and women who sent us here.

I know that for many Americans watching right now, the state of our economy is a concern that rises above all others. And rightly so. If you haven't been personally affected by this recession, you probably know someone who has – a friend; a neighbor; a member of your family. You don't need to hear another list of statistics to know that our economy is in crisis, because you live it every day. It's the worry you wake up with and the source of sleepless nights. It's the job you thought you'd retire from but now have lost; the business you built your dreams upon that's now hanging by a thread; the college acceptance letter your child had to put back in the envelope. The impact of this recession is real, and it is everywhere.

But while our economy may be weakened and our confidence shaken; though we are living through difficult and uncertain times, tonight I want every American to know this:

We will rebuild, we will recover, and the United States of America will emerge stronger than before.

The weight of this crisis will not determine the destiny of this nation. The answers to our problems don't lie beyond our reach. They exist in our laboratories and universities; in our fields and our factories; in the imaginations of our entrepreneurs and the pride of the hardest-working people on Earth. Those qualities that have made America the greatest force of progress and prosperity in human history we still possess in ample measure. What is required now is for this country to pull together, confront boldly the challenges we face, and take responsibility for our future once more.

Now, if we're honest with ourselves, we'll admit that for too long, we have not always met these responsibilities – as a government or as a people. I say this not to lay blame or look backwards, but because it is only by understanding how we arrived at this moment that we'll be able to lift ourselves out of this predicament.

The fact is, our economy did not fall into decline overnight. Nor did all of our problems begin when the housing market collapsed or the stock market sank. We have known for decades that our survival depends on finding new sources of energy. Yet we import more oil today than ever before. The cost of health care eats up more and more of our savings each year, yet we keep delaying reform. Our children will compete for jobs in a global economy that too many of our schools do not prepare them for. And though all these challenges went unsolved, we still managed to spend more money and pile up more debt, both as individuals and through our government, than ever before.

In other words, we have lived through an era where too often, short-term gains were prized over long-term prosperity; where we failed to look beyond the next payment, the next quarter, or the next election. A surplus became an excuse to transfer wealth to the wealthy instead of an opportunity to invest in our future. Regulations were gutted for the sake of a quick profit at the expense of a healthy market. People bought homes they knew they couldn't afford from banks and lenders who pushed those bad loans anyway. And all the while, critical debates and difficult decisions were put off for some other time on some other day.

Well that day of reckoning has arrived, and the time to take charge of our future is here.

Now is the time to act boldly and wisely – to not only revive this economy, but to build a new foundation for lasting prosperity. Now is the time to jumpstart job creation, re-start lending, and invest in areas like energy, health care, and education that will grow our economy, even as we make hard choices to bring our deficit down. That is what my economic agenda is designed to do, and that's what I'd like to talk to you about tonight.

WATCH THE VIDEO

February 24, 2009 4:30 PM

The President Addresses Joint Session of Congress: February 24, 2009

BLOG POSTS ON THIS ISSUE

January 23, 2013 12:45 PM EST

Fireside Hangouts: Vice President Biden Joins a Conversation on Reducing Gun Violence

On Thursday, January 24 at 1:45 p.m. ET, Vice President Biden will host the latest "Fireside Hangout" – a 21st century take on FDR's famous radio addresses – to talk about reducing gun violence.

January 23, 2013 10:40 AM EST

Surprise! President and Mrs. Obama Greet White House Tour (Bo Was There, Too)

The President and First Lady welcomed the guests with handshakes, hugs and even fistbumps, and Bo was treated to a near-constant stream of affectionate pats and petting.

January 21, 2013 3:26 PM EST

Be a Part of the Next Four Years

The President's second term will offer many ways

It's an agenda that begins with jobs.

As soon as I took office, I asked this Congress to send me a recovery plan by President's Day that would put people back to work and put money in their pockets. Not because I believe in bigger government – I don't. Not because I'm not mindful of the massive debt we've inherited – I am. I called for action because the failure to do so would have cost more jobs and caused more hardships. In fact, a failure to act would have worsened our long-term deficit by assuring weak economic growth for years. That's why I pushed for quick action. And tonight, I am grateful that this Congress delivered, and pleased to say that the American Recovery and Reinvestment Act is now law.

Over the next two years, this plan will save or create 3.5 million jobs. More than 90% of these jobs will be in the private sector – jobs rebuilding our roads and bridges; constructing wind turbines and solar panels; laying broadband and expanding mass transit.

Because of this plan, there are teachers who can now keep their jobs and educate our kids. Health care professionals can continue caring for our sick. There are 57 police officers who are still on the streets of Minneapolis tonight because this plan prevented the layoffs their department was about to make.

Because of this plan, 95% of the working households in America will receive a tax cut – a tax cut that you will see in your paychecks beginning on April 1st.

Because of this plan, families who are struggling to pay tuition costs will receive a $2,500 tax credit for all four years of college. And Americans who have lost their jobs in this recession will be able to receive extended unemployment benefits and continued health care coverage to help them weather this storm.

I know there are some in this chamber and watching at home who are skeptical of whether this plan will work. I understand that skepticism. Here in Washington, we've all seen how quickly good intentions can turn into broken promises and wasteful spending. And with a plan of this scale comes enormous responsibility to get it right.

That is why I have asked Vice President Biden to lead a tough, unprecedented oversight effort – because nobody messes with Joe. I have told each member of my Cabinet as well as mayors and governors across the country that they will be held accountable by me and the American people for every dollar they spend. I have appointed a proven and aggressive Inspector General to ferret out any and all cases of waste and fraud. And we have created a new website called recovery.gov so that every American can find out how and where their money is being spent.

So the recovery plan we passed is the first step in getting our economy back on track. But it is just the first step. Because even if we manage this plan flawlessly, there will be no real recovery unless we clean up the credit crisis that has severely weakened our financial system.

I want to speak plainly and candidly about this issue tonight, because every American should know that it directly affects you and your family's well-being. You should also know that the money you've deposited in banks across the country is safe; your insurance is secure; and you can rely on the continued operation of our financial system. That is not the source of concern.

The concern is that if we do not re-start lending in this country, our recovery will be choked off before it even begins.

You see, the flow of credit is the lifeblood of our economy. The ability to get a loan is how you finance the purchase of everything from a home to a car to a college education; how stores stock their shelves, farms buy equipment, and businesses make payroll.

But credit has stopped flowing the way it should. Too many bad loans from the housing crisis have made their way onto the books of too many banks. With so much debt and so little confidence, these banks are now fearful of lending out any more money to households, to businesses, or to each other. When there is no lending, families can't afford to buy homes or cars. So businesses are forced to make layoffs. Our economy suffers even more, and credit dries up even further.

That is why this administration is moving swiftly and aggressively to break this destructive cycle, restore confidence, and re-start lending.

We will do so in several ways. First, we are creating a new lending fund that represents the largest effort ever to help provide auto loans, college loans, and small business loans to the consumers and entrepreneurs who keep this economy running.

Second, we have launched a housing plan that will help responsible families facing the threat of foreclosure lower their monthly payments and re-finance their mortgages. It's a plan that won't help speculators or that neighbor down the street who bought a house he could never hope to afford, but it will help millions of Americans who are struggling with declining home values – Americans who will now be able to take advantage of the lower interest rates that this plan has already helped bring about. In fact, the average family who re-finances today can save nearly $2000 per year on their mortgage.

Third, we will act with the full force of the federal government to ensure that the major banks that Americans depend on have enough confidence and enough money to lend even in more difficult times. And when we learn that a major bank has serious problems, we will hold accountable those responsible, force the necessary adjustments, provide the support to clean up their balance sheets, and assure the continuity of a strong, viable institution that can serve our people and our economy.

I understand that on any given day, Wall Street may be more comforted by an approach that gives banks bailouts with no strings attached, and that holds nobody accountable for their reckless decisions. But such an approach won't solve the problem. And our goal is to quicken the day when we re-start lending to the American people and American business and end this crisis once and for all.

I intend to hold these banks fully accountable for the assistance they receive, and this time, they will have to clearly demonstrate how taxpayer dollars result in more lending for the American taxpayer. This time, CEOs won't be able to use taxpayer money to pad their paychecks or buy fancy drapes or disappear on a private jet. Those days are over.

Still, this plan will require significant resources from the federal government – and yes, probably more than we've already set aside. But while the cost of action will be great, I can assure you that the cost of inaction will be far greater, for it could result in an economy that sputters along for not months or years, but perhaps a decade. That would be worse for our deficit, worse for business, worse for you, and worse for the next generation. And I refuse to let that happen.

I understand that when the last administration asked this Congress to provide assistance for struggling banks, Democrats and Republicans alike were infuriated by the mismanagement and results that followed. So were the American taxpayers. So was I.

So I know how unpopular it is to be seen as helping banks right now, especially when everyone is suffering in part from their bad decisions. I promise you – I get it.

But I also know that in a time of crisis, we cannot afford to govern out of anger, or yield to the politics of the moment. My job – our job – is to solve the problem. Our job is to govern with a sense of responsibility. I will not spend a single penny for the purpose of rewarding a single Wall Street executive, but I will do whatever it takes to help the small business that can't pay its workers or the family that has saved and still can't get a mortgage.

That's what this is about. It's not about helping banks – it's about helping people. Because when credit is available again, that young family can finally buy a new home. And then some company will hire workers to build it. And then those workers will have money to spend, and if they can get a loan too, maybe they'll finally buy that car, or open their own business. Investors will return to the market, and American families will see their retirement secured once more. Slowly, but surely, confidence will return, and our economy will recover.

So I ask this Congress to join me in doing whatever proves necessary. Because we cannot consign our nation to an open-ended recession. And to ensure that a crisis of this magnitude never happens again, I ask Congress to move quickly on legislation that will finally reform our outdated regulatory system. It is time to put in place tough, new common-sense rules of the road so that our financial market rewards drive and innovation, and punishes short-cuts and abuse.

The recovery plan and the financial stability plan are the immediate steps we're taking to revive our economy in the short-term. But the only way to fully restore America's economic strength is to make the long-term investments that will lead to new jobs, new industries, and a renewed ability to compete with the rest of the world. The only way this century will be another American century is if we confront at last the price of our dependence on oil and the high cost of health care; the schools that aren't preparing our children and the mountain of debt they stand to inherit. That is our responsibility.

In the next few days, I will submit a budget to Congress. So often, we have come to view these documents as simply numbers on a page or laundry lists of programs. I see this document differently. I see it as a vision for America – as a blueprint for our future.

My budget does not attempt to solve every problem or address every issue. It reflects the stark reality of what we've inherited – a trillion dollar deficit, a financial crisis, and a costly recession.

Given these realities, everyone in this chamber – Democrats and Republicans – will have to sacrifice some worthy priorities for which there are no dollars. And that includes me.

But that does not mean we can afford to ignore our long-term challenges. I reject the view that says our problems will simply take care of themselves; that says government has no role in laying the foundation for our common prosperity.

For history tells a different story. History reminds us that at every moment of economic upheaval and transformation, this nation has responded with bold action and big ideas. In the midst of civil war, we laid railroad tracks from one coast to another that spurred commerce and industry. From the turmoil of the Industrial Revolution came a system of public high schools that prepared our citizens for a new age. In the wake of war and depression, the GI Bill sent a generation to college and created the largest middle-class in history. And a twilight struggle for freedom led to a nation of highways, an American on the moon, and an explosion of technology that still shapes our world.

In each case, government didn't supplant private enterprise; it catalyzed private enterprise. It created the conditions for thousands of entrepreneurs and new businesses to adapt and to thrive.

We are a nation that has seen promise amid peril, and claimed opportunity from ordeal. Now we must be that nation again. That is why, even as it cuts back on the programs we don't need, the budget I submit will invest in the three areas that are absolutely critical to our economic future: energy, health care, and education.

It begins with energy.

We know the country that harnesses the power of clean, renewable energy will lead the 21st century. And yet, it is China that has launched the largest effort in history to make their economy energy efficient. We invented solar technology, but we've fallen behind countries like Germany and Japan in producing it. New plug-in hybrids roll off our assembly lines, but they will run on batteries made in Korea.

Well I do not accept a future where the jobs and industries of tomorrow take root beyond our borders – and I know you don't either. It is time for America to lead again.

Thanks to our recovery plan, we will double this nation's supply of renewable energy in the next three years. We have also made the largest investment in basic research funding in American history – an investment that will spur not only new discoveries in energy, but breakthroughs in medicine, science, and technology.

We will soon lay down thousands of miles of power lines that can carry new energy to cities and towns across this country. And we will put Americans to work making our homes and buildings more efficient so that we can save billions of dollars on our energy bills.

But to truly transform our economy, protect our security, and save our planet from the ravages of climate change, we need to ultimately make clean, renewable energy the profitable kind of energy. So I ask this Congress to send me legislation that places a market-based cap on carbon pollution and drives the production of more renewable energy in America. And to support that innovation, we will invest fifteen billion dollars a year to develop technologies like wind power and solar power; advanced biofuels, clean coal, and more fuel-efficient cars and trucks built right here in America.

As for our auto industry, everyone recognizes that years of bad decision-making and a global recession have pushed our automakers to the brink. We should not, and will not, protect them from their own bad practices. But we are committed to the goal of a re-tooled, re-imagined auto industry that can compete and win. Millions of jobs depend on it. Scores of communities depend on it. And I believe the nation that invented the automobile cannot walk away from it.

None of this will come without cost, nor will it be easy. But this is America. We don't do what's easy. We do what is necessary to move this country forward.

For that same reason, we must also address the crushing cost of health care.

This is a cost that now causes a bankruptcy in America every thirty seconds. By the end of the year, it could cause 1.5 million Americans to lose their homes. In the last eight years, premiums have grown four times faster than wages. And in each of these years, one million more Americans have lost their health insurance. It is one of the major reasons why small businesses close their doors and corporations ship jobs overseas. And it's one of the largest and fastest-growing parts of our budget.

Given these facts, we can no longer afford to put health care reform on hold.

Already, we have done more to advance the cause of health care reform in the last thirty days than we have in the last decade. When it was days old, this Congress passed a law to provide and protect health insurance for eleven million American children whose parents work full-time. Our recovery plan will invest in electronic health records and new technology that will reduce errors, bring down costs, ensure privacy, and save lives. It will launch a new effort to conquer a disease that has touched the life of nearly every American by seeking a cure for cancer in our time. And it makes the largest investment ever in preventive care, because that is one of the best ways to keep our people healthy and our costs under control.

This budget builds on these reforms. It includes an historic commitment to comprehensive health care reform – a down-payment on the principle that we must have quality, affordable health care for every American. It's a commitment that's paid for in part by efficiencies in our system that are long overdue. And it's a step we must take if we hope to bring down our deficit in the years to come.

Now, there will be many different opinions and ideas about how to achieve reform, and that is why I'm bringing together businesses and workers, doctors and health care providers, Democrats and Republicans to begin work on this issue next week.

I suffer no illusions that this will be an easy process. It will be hard. But I also know that nearly a century after Teddy Roosevelt first called for reform, the cost of our health care has weighed down our economy and the conscience of our nation long enough. So let there be no doubt: health care reform cannot wait, it must not wait, and it will not wait another year.

The third challenge we must address is the urgent need to expand the promise of education in America.

In a global economy where the most valuable skill you can sell is your knowledge, a good education is no longer just a pathway to opportunity – it is a pre-requisite.

Right now, three-quarters of the fastest-growing occupations require more than a high school diploma. And yet, just over half of our citizens have that level of education. We have one of the highest high school dropout rates of any industrialized nation. And half of the students who begin college never finish.

This is a prescription for economic decline, because we know the countries that out-teach us today will out-compete us tomorrow. That is why it will be the goal of this administration to ensure that every child has access to a complete and competitive education – from the day they are born to the day they begin a career.

Already, we have made an historic investment in education through the economic recovery plan. We have dramatically expanded early childhood education and will continue to improve its quality, because we know that the most formative learning comes in those first years of life. We have made college affordable for nearly seven million more students. And we have provided the resources necessary to prevent painful cuts and teacher layoffs that would set back our children's progress.

But we know that our schools don't just need more resources. They need more reform. That is why this budget creates new incentives for teacher performance; pathways for advancement, and rewards for success. We'll invest in innovative programs that are already helping schools meet high standards and close achievement gaps. And we will expand our commitment to charter schools.

It is our responsibility as lawmakers and educators to make this system work. But it is the responsibility of every citizen to participate in it. And so tonight, I ask every American to commit to at least one year or more of higher education or career training. This can be community college or a four-year school; vocational training or an apprenticeship. But whatever the training may be, every American will need to get more than a high school diploma. And dropping out of high school is no longer an option. It's not just quitting on yourself, it's quitting on your country – and this country needs and values the talents of every American. That is why we will provide the support necessary for you to complete college and meet a new goal: by 2020, America will once again have the highest proportion of college graduates in the world.

I know that the price of tuition is higher than ever, which is why if you are willing to volunteer in your neighborhood or give back to your community or serve your country, we will make sure that you can afford a higher education. And to encourage a renewed spirit of national service for this and future generations, I ask this Congress to send me the bipartisan legislation that bears the name of Senator Orrin Hatch as well as an American who has never stopped asking what he can do for his country – Senator Edward Kennedy.

These education policies will open the doors of opportunity for our children. But it is up to us to ensure they walk through them. In the end, there is no program or policy that can substitute for a mother or father who will attend those parent/teacher conferences, or help with homework after dinner, or turn off the TV, put away the video games, and read to their child. I speak to you not just as a President, but as a father when I say that responsibility for our children's education must begin at home.

There is, of course, another responsibility we have to our children. And that is the responsibility to ensure that we do not pass on to them a debt they cannot pay. With the deficit we inherited, the cost of the crisis we face, and the long-term challenges we must meet, it has never been more important to ensure that as our economy recovers, we do what it takes to bring this deficit down.

I'm proud that we passed the recovery plan free of earmarks, and I want to pass a budget next year that ensures that each dollar we spend reflects only our most important national priorities.

Yesterday, I held a fiscal summit where I pledged to cut the deficit in half by the end of my first term in office. My administration has also begun to go line by line through the federal budget in order to eliminate wasteful and ineffective programs. As you can imagine, this is a process that will take some time. But we're starting with the biggest lines. We have already identified two trillion dollars in savings over the next decade.

In this budget, we will end education programs that don't work and end direct payments to large agribusinesses that don't need them. We'll eliminate the no-bid contracts that have wasted billions in Iraq, and reform our defense budget so that we're not paying for Cold War-era weapons systems we don't use. We will root out the waste, fraud, and abuse in our Medicare program that doesn't make our seniors any healthier, and we will restore a sense of fairness and balance to our tax code by finally ending the tax breaks for corporations that ship our jobs overseas.

In order to save our children from a future of debt, we will also end the tax breaks for the wealthiest 2% of Americans. But let me perfectly clear, because I know you'll hear the same old claims that rolling back these tax breaks means a massive tax increase on the American people: if your family earns less than $250,000 a year, you will not see your taxes increased a single dime. I repeat: not one single dime. In fact, the recovery plan provides a tax cut – that's right, a tax cut – for 95% of working families. And these checks are on the way.

To preserve our long-term fiscal health, we must also address the growing costs in Medicare and Social Security. Comprehensive health care reform is the best way to strengthen Medicare for years to come. And we must also begin a conversation on how to do the same for Social Security, while creating tax-free universal savings accounts for all Americans.

Finally, because we're also suffering from a deficit of trust, I am committed to restoring a sense of honesty and accountability to our budget. That is why this budget looks ahead ten years and accounts for spending that was left out under the old rules – and for the first time, that includes the full cost of fighting in Iraq and Afghanistan. For seven years, we have been a nation at war. No longer will we hide its price.

We are now carefully reviewing our policies in both wars, and I will soon announce a way forward in Iraq that leaves Iraq to its people and responsibly ends this war.

And with our friends and allies, we will forge a new and comprehensive strategy for Afghanistan and Pakistan to defeat al Qaeda and combat extremism. Because I will not allow terrorists to plot against the American people from safe havens half a world away.

As we meet here tonight, our men and women in uniform stand watch abroad and more are readying to deploy. To each and every one of them, and to the families who bear the quiet burden of their absence, Americans are united in sending one message: we honor your service, we are inspired by your sacrifice, and you have our unyielding support. To relieve the strain on our forces, my budget increases the number of our soldiers and Marines. And to keep our sacred trust with those who serve, we will raise their pay, and give our veterans the expanded health care and benefits that they have earned.

To overcome extremism, we must also be vigilant in upholding the values our troops defend – because there is no force in the world more powerful than the example of America. That is why I have ordered the closing of the detention center at Guantanamo Bay, and will seek swift and certain justice for captured terrorists – because living our values doesn't make us weaker, it makes us safer and it makes us stronger. And that is why I can stand here tonight and say without exception or equivocation that the United States of America does not torture.

In words and deeds, we are showing the world that a new era of engagement has begun. For we know that America cannot meet the threats of this century alone, but the world cannot meet them without America. We cannot shun the negotiating table, nor ignore the foes or forces that could do us harm. We are instead called to move forward with the sense of confidence and candor that serious times demand.

To seek progress toward a secure and lasting peace between Israel and her neighbors, we have appointed an envoy to sustain our effort. To meet the challenges of the 21st century – from terrorism to nuclear proliferation; from pandemic disease to cyber threats to crushing poverty – we will strengthen old alliances, forge new ones, and use all elements of our national power.

And to respond to an economic crisis that is global in scope, we are working with the nations of the G-20 to restore confidence in our financial system, avoid the possibility of escalating protectionism, and spur demand for American goods in markets across the globe. For the world depends on us to have a strong economy, just as our economy depends on the strength of the world's.

As we stand at this crossroads of history, the eyes of all people in all nations are once again upon us – watching to see what we do with this moment; waiting for us to lead.

Those of us gathered here tonight have been called to govern in extraordinary times. It is a tremendous burden, but also a great privilege – one that has been entrusted to few generations of Americans. For in our hands lies the ability to shape our world for good or for ill.

I know that it is easy to lose sight of this truth – to become cynical and doubtful; consumed with the petty and the trivial.

But in my life, I have also learned that hope is found in unlikely places; that inspiration often comes not from those with the most power or celebrity, but from the dreams and aspirations of Americans who are anything but ordinary.

I think about Leonard Abess, the bank president from Miami who reportedly cashed out of his company, took a $60 million bonus, and gave it out to all 399 people who worked for him, plus another 72 who used to work for him. He didn't tell anyone, but when the local newspaper found out, he simply said, "I knew some of these people since I was 7 years old. I didn't feel right getting the money myself."

I think about Greensburg, Kansas, a town that was completely destroyed by a tornado, but is being rebuilt by its residents as a global example of how clean energy can power an entire community – how it can bring jobs and businesses to a place where piles of bricks and rubble once lay. "The tragedy was terrible," said one of the men who helped them rebuild. "But the folks here know that it also provided an incredible opportunity."

And I think about Ty'Sheoma Bethea, the young girl from that school I visited in Dillon, South Carolina – a place where the ceilings leak, the paint peels off the walls, and they have to stop teaching six times a day because the train barrels by their classroom. She has been told that her school is hopeless, but the other day after class she went to the public library and typed up a letter to the people sitting in this room. She even asked her principal for the money to buy a stamp. The letter asks us for help, and says, "We are just students trying to become lawyers, doctors, congressmen like yourself and one day president, so we can make a change to not just the state of South Carolina but also the world. We are not quitters."

We are not quitters.

These words and these stories tell us something about the spirit of the people who sent us here. They tell us that even in the most trying times, amid the most difficult circumstances, there is a generosity, a resilience, a decency, and a determination that perseveres; a willingness to take responsibility for our future and for posterity.

Their resolve must be our inspiration. Their concerns must be our cause. And we must show them and all our people that we are equal to the task before us.

I know that we haven't agreed on every issue thus far, and there are surely times in the future when we will part ways. But I also know that every American who is sitting here tonight loves this country and wants it to succeed. That must be the starting point for every debate we have in the coming months, and where we return after those debates are done. That is the foundation on which the American people expect us to build common ground.

And if we do – if we come together and lift this nation from the depths of this crisis; if we put our people back to work and restart the engine of our prosperity; if we confront without fear the challenges of our time and summon that enduring spirit of an America that does not quit, then someday years from now our children can tell their children that this was the time when we performed, in the words that are carved into this very chamber, "something worthy to be remembered." Thank you, God Bless you, and may God Bless the United States of America.